nationalgrid

Thomas R. Teehan
Senior Counsel

July 22, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
Response to Data Requests

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to the Division's fifth, sixth, seventh, eighth, ninth and tenth sets of data requests issued in the above-referenced proceeding. In addition, responses are included to the Commission's first set of data requests and the Navy's second set. Attached is a listing of the data requests issued to date and designating the responses included in this filing.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4065 Service List

[1] The Narragansett Electric Company d/b/a National Grid ("Company").

nationalgrid

Thomas R. Teehan
Senior Counsel

July 22, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
<u>Motion for Protective Treatment</u>

Dear Ms. Massaro:

Enclosed please find an original and nine (9) copies of National Grid's[1] Motion for Protective Treatment concerning the Company's response to the Division's fifth set of data requests being filed under separate cover in the above-captioned proceeding. Specifically, the Company is requesting confidential treatment of its response to Data Request DIV 5-A. The Company's Motion is submitted herewith pursuant to Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(i)(B).

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4065 Service List

[1] The Narragansett Electric Company d/b/a National Grid ("Company").

280 Melrose Street, Providence, RI 02907
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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

National Grid Application to Change Rate Schedules	)	Docket 3943

MOTION OF NATIONAL GRID
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

Now comes The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company") and hereby requests that the Rhode Island Public Utilities Commission (the "Commission) grant protection from public disclosure of certain confidential, competitively sensitive and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and by R.I.G.L. § 38-2-2(4)(i)(B).

I. BACKGROUND

On June 18, 2009, the Company filed responses to data requests issued by the Division in the above-referenced proceeding concerning the Company's application for a change in base rates. In those data requests, the Division requested confidential customer data including customer names and accounts numbers associated with bad-debt accounts. The Company is submitting the information in response to Data Request DIV-5-A. For the reasons stated below, the Company requests that the customer data be protected from public disclosure. For the public record, the Company has filed a redacted version of the data request with the confidential customer data removed from the response.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(i)(B) provides that the following records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that the determination as to whether this exemption applies requires the application of a two-pronged test set forth in Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001). The first prong of the test assesses whether the information was provided voluntarily to the governmental agency. Providence Journal, 774 A.2d at 47. If the answer to the first question is affirmative, then the question becomes whether the information is "of a kind that would customarily not be released to the public by the person from whom it was obtained." Id.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established by the Court in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under this balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

III. BASIS FOR CONFIDENTIALITY

National Grid seeks protection from public disclosure for the confidential and proprietary compensation amounts set forth in the Company's response to Data Request DIV-5-A. The customer data involves information that is private to the named customers and sensitive to the Company in terms of its obligation to protect confidential customer data. If this information was disclosed on the public record, it could affect both the Company's ability to protect customer relationships and its ability to serve customers effectively. In addition, public disclosure of the confidential and proprietary customer data could be harmful to the named customers since the information involves their private financial affairs.

Consistent with the standard for confidentiality established under Rhode Island law, the confidential price terms are information "of a kind that would customarily not be released to the public by the person from whom it was obtained." The Company is under no obligation in any other forum to disclose the information and, as is customary in relation to confidential customer data, the Company would not ordinarily release the information in a public forum because of the detrimental impact that such a release would have on the private interests of its customers. Accordingly, in this case, the need to ensure that the confidential and proprietary customer data are protected outweighs the general public interest inherent in disclosure of information pending before regulatory agencies.

V. CONCLUSION

The confidential and proprietary customer data contained in the Company's response to Data Request DIV-5-A should be protected from the public record, because release of this information would be detrimental to the public interest. The information is private to the customer. Accordingly, the Company requests that the Commission protect the confidential information submitted in response to Data Request DIV-5-A.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorneys,

____
Thomas R. Teehan, Esq.
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7667

____
Cheryl M. Kimball, Esq. (RI #6458)
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400

Dated: July 22, 2009

Commission Data Request 1-5

Request:

Please provide the following information for the Company for each month of the years 2008 and 2009 through the present:

(1) the budgeted and actual monthly income statements;

(2) a Statement of Cash Flows; and

(3) the short-term debt balance, short-term interest expense and rate as well as a comparison of the short-term interest rate to the contemporaneous prime rate.

Response:

(1) Attachment COMM 1-5-1 presents the budgeted and actual monthly income statements for The Narragansett Electric Company for CY08 and CY09 (through June).

(2) Attachment COMM 1-5-2 presents the Statement of Cash Flows as of March 31, 2009 for The Narragansett Electric Company. Please note that the cash flows include both the gas and electric operations because the Company does not track cash flows for these operations separately.

(3) Attachment COMM 1-5-3 presents the short-term debt balance, short-term interest expense and rate as well as a comparison of the short-term interest rate to the contemporaneous prime rate.

Narragansett Electric Company
CY08 & CY09 (through March)
Actuals
$000's

	CY 2008 JAN	CY 2008 FEB	CY 2008 MAR	CY 2008 APRIL	CY 2008 MAY	CY 2008 JUNE	CY 2008 JULY	CY 2008 AUG	CY 2008 SEPT
TOTAL OPERATING REVENUES	85,202.9	78,443.7	87,404.2	76,815.3	110,204.3	90,585.1	129,819.4	104,166.2	99,950.1
TOTAL OTHER INCOME	524.1	577.3	876.8	574.9	615.4	875.9	306.0	601.9	675.6
OTHER OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL INCOME	85,727.0	79,021.0	88,281.0	77,390.2	110,819.7	91,461.0	130,125.4	104,768.1	100,625.7
OPERATING EXPENSES									
Staff Costs									
Subtotal Payroll	3,111.2	3,908.1	3,733.0	3,619.0	3,990.7	3,639.3	3,957.5	3,765.6	4,169.4
Subtotal Benefits	1,857.5	1,739.4	2,200.6	1,759.2	1,577.2	2,039.1	1,601.8	1,642.4	2,364.8
Payroll Taxes	403.1	322.8	283.0	261.4	304.2	375.8	319.3	293.5	284.6
Subtotal Staff Costs	5,371.7	5,970.3	6,216.6	5,639.6	5,872.1	6,054.2	5,878.6	5,701.6	6,818.8
Other Expenses									
Other Expenses-Detail	4,234.5	5,207.8	8,317.7	3,252.1	4,830.5	5,075.0	4,684.5	6,479.7	9,757.6
Rents	537.1	563.7	633.3	514.2	438.0	492.7	547.0	541.4	542.3
Other Expenses-Other	1,925.1	1,196.6	3,398.8	1,420.9	1,596.2	2,115.9	2,515.8	1,167.3	2,991.5
Subtotal Other Expenses	6,696.8	6,968.1	12,349.8	5,187.3	6,864.7	7,683.6	7,747.4	8,188.4	13,291.4
Total Staff & Other Exp	12,068.5	12,938.4	18,566.4	10,826.9	12,736.8	13,737.9	13,626.0	13,890.0	20,110.2
Purchased Power - Electricity	56,541.9	52,181.0	55,668.1	50,021.6	76,722.4	63,482.7	91,524.8	73,075.7	69,887.3
Purchased Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trans Credit from Affiliates	(3,509.8)	(2,511.1)	(2,777.8)	(5,350.3)	(2,047.7)	(2,740.7)	(3,675.5)	(3,055.9)	(3,019.0)
Total Wheeling	6,373.3	5,682.9	8,139.3	6,405.4	13,196.7	5,093.3	6,884.0	7,944.0	7,963.6
Total Depreciation Expense	3,569.3	3,583.5	3,601.4	3,636.6	3,663.7	3,683.1	3,705.8	3,733.8	3,764.2
Total Amortization Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Property Taxes / Rates	4,989.5	4,446.3	5,757.6	4,634.2	6,069.0	5,148.6	6,820.0	5,597.7	5,711.6
TOTAL OPERATING EXPENSES	80,032.7	76,321.1	88,955.0	70,174.4	110,340.8	88,404.9	118,885.1	101,185.3	104,417.9

$000's	CY 2008 JAN	CY 2008 FEB	CY 2008 MAR	CY 2008 APRIL	CY 2008 MAY	CY 2008 JUNE	CY 2008 JULY	CY 2008 AUG	CY 2008 SEPT
OPERATING INCOME	5,694.3	2,699.9	(673.9)	7,215.8	478.9	3,056.1	11,240.3	3,582.8	(3,792.2)
Total Equity in Subsidiaries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE GOODWILL	5,694.3	2,699.9	(673.9)	7,215.8	478.9	3,056.1	11,240.3	3,582.8	(3,792.2)
Goodwill Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING PROFIT	5,694.3	2,699.9	(673.9)	7,215.8	478.9	3,056.1	11,240.3	3,582.8	(3,792.2)
Excep-Merger Costs-Non Oper	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exceptional-Other Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dividend Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE INTEREST & TAXES	5,694.3	2,699.9	(673.9)	7,215.8	478.9	3,056.1	11,240.3	3,582.8	(3,792.2)
Total External Interest	492.4	439.6	837.4	461.8	253.6	367.4	420.2	316.4	535.2
Total Internal Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Interest	492.4	439.6	837.4	461.8	253.6	367.4	420.2	316.4	535.2
PROFIT BEFORE TAX	5,201.9	2,260.3	(1,511.3)	6,754.0	225.3	2,688.7	10,820.1	3,266.4	(4,327.4)
Total Taxes	(467.4)	768.8	(1,595.7)	2,252.0	(45.1)	872.7	3,612.8	917.5	(1,521.2)
Sh of Assoc/JV Post-Tax Profit	5,682.5	6,261.5	402.4	9,572.6	(9,972.4)	(2,560.1)	(3,021.3)	(1,410.2)	(5,336.8)
PROFIT AFTER TAXES	11,351.8	7,753.0	486.8	14,074.6	(9,702.0)	(744.1)	4,186.0	938.7	(8,143.0)
Minority Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Dividends	(93.6)	0.0	0.0	0.0	27.6	0.0	0.0	0.0	27.6
PROFIT ATTRIB TO SHAREHOLDERS	11,445.5	7,753.0	486.8	14,074.6	(9,729.6)	(744.1)	4,186.0	938.7	(8,170.6)
Common Dividends	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RETAINED PROFIT	11,445.5	7,753.0	486.8	14,074.6	(9,729.6)	(744.1)	4,186.0	938.7	(8,170.6)

CY 2008 OCT	CY 2008 NOV	CY 2008 DEC	CY 2008 Annual	CY 2009 JAN	CY 2009 FEB	CY 2009 MAR	CY 2009 APRIL	CY 2009 MAY	CY 2009 JUNE	CY 2009 Year to Date
92,794.0	94,549.3	96,189.8	1,146,124.2	96,533.5	82,051.9	74,808.7	71,580.0	70,833.3	71,674.6	467,482.0
672.7	555.8	2,296.8	9,153.2	620.4	534.0	(1,342.3)	650.1	557.7	670.8	1,690.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93,466.8	95,105.1	98,486.6	1,155,277.4	97,153.9	82,585.9	73,466.4	72,230.1	71,391.0	72,345.4	469,172.7
4,133.3	3,646.0	4,468.2	46,141.2	4,208.6	4,199.3	4,572.1	4,064.2	4,011.4	3,640.6	24,696.2
1,838.1	1,455.2	480.0	20,555.3	1,233.8	1,034.6	2,583.6	2,022.7	3,013.1	4,686.4	14,574.2
291.5	222.9	200.9	3,563.3	428.3	320.3	333.4	321.0	296.5	465.0	2,164.5
6,262.9	5,324.1	5,149.2	70,259.8	5,870.7	5,554.3	7,489.1	6,407.8	7,320.9	8,792.0	41,434.9
			0.0							
4,520.1	5,980.6	5,758.4	68,098.6	5,417.5	5,678.3	14,136.8	3,166.3	4,142.5	6,116.0	38,657.5
483.3	562.5	414.0	6,269.7	458.7	469.1	545.6	351.3	351.4	487.4	2,663.5
1,625.2	2,232.2	2,313.3	24,498.9	1,069.9	1,890.3	1,450.2	1,957.6	1,379.2	1,600.5	9,347.7
6,628.6	8,775.3	8,485.7	98,867.1	6,946.0	8,037.7	16,132.6	5,475.3	5,873.1	8,203.9	50,668.6
12,891.6	14,099.4	13,634.9	169,127.0	12,816.8	13,592.0	23,621.7	11,883.1	13,194.1	16,995.9	92,103.5
63,626.3	62,585.2	63,508.3	778,825.3	69,906.5	54,886.1	43,029.8	46,176.2	43,706.8	43,030.3	300,735.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4,004.5)	(3,517.0)	(2,673.5)	(38,882.8)	(1,839.5)	(3,896.0)	(5,142.3)	(5,767.6)	(1,744.0)	(3,433.8)	(21,823.2)
8,073.4	7,362.3	6,281.2	89,399.6	6,288.7	7,454.6	8,079.6	6,855.3	6,101.8	6,692.0	41,472.0
3,771.4	3,772.8	3,785.0	44,270.7	3,797.8	3,809.4	3,823.0	3,834.8	3,844.2	3,854.1	22,963.3
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5,374.1	5,502.9	5,562.9	65,614.2	5,463.6	4,952.0	4,515.0	4,658.0	4,671.8	4,672.9	28,933.2
89,732.3	89,805.7	90,098.9	1,108,354.0	96,433.9	80,798.2	77,926.7	67,639.8	69,774.6	71,811.3	464,384.6

CY 2008 OCT	CY 2008 NOV	CY 2008 DEC	CY 2008 Annual	CY 2009 JAN	CY 2009 FEB	CY 2009 MAR	CY 2009 APRIL	CY 2009 MAY	CY 2009 JUNE	CY 2009 Year to Date
3,734.5	5,299.4	8,387.7	46,923.4	720.0	1,787.7	(4,460.3)	4,590.3	1,616.3	534.1	4,788.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3,734.5	5,299.4	8,387.7	46,923.4	720.0	1,787.7	(4,460.3)	4,590.3	1,616.3	534.1	4,788.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3,734.5	5,299.4	8,387.7	46,923.4	720.0	1,787.7	(4,460.3)	4,590.3	1,616.3	534.1	4,788.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3,734.5	5,299.4	8,387.7	46,923.4	720.0	1,787.7	(4,460.3)	4,590.3	1,616.3	534.1	4,788.1
578.8	345.5	465.8	5,514.0	420.0	366.6	348.3	331.5	308.2	219.7	1,994.3
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
578.8	345.5	465.8	5,514.0	420.0	366.6	348.3	331.5	308.2	219.7	1,994.3
3,155.6	4,953.9	7,921.9	41,409.4	300.0	1,421.1	(4,808.6)	4,258.8	1,308.1	314.3	2,793.8
1,262.0	2,090.4	1,523.2	9,669.8	59.3	148.6	(2,060.7)	825.5	938.1	(189.2)	(278.4)
(524.9)	943.2	8,880.3	8,916.7	5,478.8	10,116.7	(1,090.9)	842.6	(981.3)	(4,769.3)	9,596.6
1,368.8	3,806.7	15,278.9	40,656.3	5,719.5	11,389.2	(3,838.8)	4,275.8	(611.2)	(4,265.8)	12,668.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	27.6	0.0	(10.8)	0.0	27.6	0.0	0.0	0.0	27.6	55.2
1,368.8	3,779.1	15,278.9	40,667.1	5,719.5	11,361.5	(3,838.8)	4,275.8	(611.2)	(4,293.4)	12,613.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1,368.8	3,779.1	15,278.9	40,667.1	5,719.5	11,361.5	(3,838.8)	4,275.8	(611.2)	(4,293.4)	12,613.5

Income Statement - YTD by Month
($ 000)

nationalgrid

Narragansett Electric Company
CY08 & CY09 (through March)
Budget
$000's

	CY 2008 JAN	CY 2008 FEB	CY 2008 MAR	CY 2008 APRIL	CY 2008 MAY	CY 2008 JUNE	CY 2008 JULY	CY 2008 AUG	CY 2008 SEPT	CY 2008 OCT	CY 2008 NOV	CY 2008 DEC	CY 2008 Annual	CY 2009 JAN
TOTAL OPERATING REVENUES	75,024.7	68,316.8	71,882.3	62,113.0	59,722.6	64,875.6	73,168.5	77,558.8	76,691.4	67,772.3	66,921.9	76,149.3	840,197.1	74,668.3
TOTAL OTHER INCOME	451.6	451.6	451.6	451.6	451.6	451.6	451.6	451.6	451.6	451.6	451.6	451.6	5,419.5	451.6
OTHER OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL INCOME	75,476.3	68,768.4	72,333.9	62,564.6	60,174.3	65,327.3	73,620.1	78,010.4	77,143.0	68,223.9	67,373.5	76,600.9	845,616.6	75,119.9
OPERATING EXPENSES														
Staff Costs														
Subtotal Payroll	3,658.3	3,198.5	3,326.8	3,529.6	3,894.9	3,570.7	3,887.9	3,581.8	3,593.4	3,903.0	3,584.7	3,527.7	43,257.3	3,832.9
Subtotal Benefits	1,767.8	1,767.8	1,767.8	1,788.7	1,788.3	1,793.2	1,784.6	1,788.6	1,798.7	1,789.1	1,789.1	1,793.9	21,417.6	1,784.7
Payroll Taxes	317.4	317.4	317.4	329.5	329.5	330.3	328.8	329.5	331.3	329.6	329.6	330.4	3,920.6	328.8
Subtotal Staff Costs	5,743.4	5,283.7	5,411.9	5,647.9	6,012.7	5,694.2	6,001.3	5,699.9	5,723.4	6,021.7	5,703.4	5,652.1	68,595.6	5,946.4
Other Expenses													0.0	
Other Expenses-Detail	4,265.4	4,126.2	4,297.4	4,358.6	4,328.4	4,469.5	4,391.3	4,401.5	4,403.9	4,338.5	4,339.3	4,499.3	52,219.4	5,079.2
Rents	499.4	494.1	511.0	328.6	316.4	316.4	316.4	316.4	315.0	316.6	315.0	315.0	4,360.2	314.9
Other Expenses-Other	1,581.0	1,270.3	1,395.1	1,676.0	1,706.4	1,630.5	1,654.9	1,638.3	2,539.3	3,447.1	4,361.3	4,384.1	27,284.3	1,647.2
Subtotal Other Expenses	6,345.7	5,890.6	6,203.6	6,363.3	6,351.2	6,416.4	6,362.6	6,356.2	7,258.2	8,102.2	9,015.7	9,198.4	83,864.0	7,041.3
Total Staff & Other Exp	12,089.2	11,174.3	11,615.5	12,011.2	12,363.8	12,110.7	12,363.9	12,056.1	12,981.6	14,123.9	14,719.0	14,850.5	152,459.5	12,987.7
Purchased Power - Electricity	48,125.5	43,798.8	46,675.2	41,422.6	39,701.3	43,472.3	49,843.5	52,746.4	52,202.7	44,836.1	43,228.8	49,809.7	555,862.8	50,594.8
Purchased Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trans Credit from Affiliates	(2,823.2)	(2,823.2)	(2,823.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(2,979.2)	(35,282.7)	(2,979.2)
Total Wheeling	3,185.7	3,185.7	3,185.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,557.0	0.0
Total Depreciation Expense	3,504.4	3,517.0	3,529.6	3,542.0	3,555.0	3,568.1	3,584.0	3,599.8	4,777.7	3,629.4	3,643.0	3,656.6	44,106.7	3,670.8
Total Amortization Expense	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	295.2	24.6
Total Property Taxes / Rates	4,767.1	4,767.1	4,767.1	4,872.7	4,872.7	4,872.7	4,872.7	4,872.7	4,872.7	4,872.7	4,872.7	4,872.7	58,155.2	4,872.7
TOTAL OPERATING EXPENSES	68,873.2	63,644.2	66,974.5	58,893.8	57,538.2	61,069.0	67,709.4	70,320.3	71,880.0	64,507.4	63,508.9	70,234.9	785,153.7	69,171.4
OPERATING INCOME	6,603.1	5,124.2	5,359.5	3,670.8	2,636.1	4,258.2	5,910.7	7,690.1	5,263.0	3,716.5	3,864.6	6,366.1	60,462.9	5,948.5
Total Equity in Subsidiaries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE GOODWILL	6,603.1	5,124.2	5,359.5	3,670.8	2,636.1	4,258.2	5,910.7	7,690.1	5,263.0	3,716.5	3,864.6	6,366.1	60,462.9	5,948.5
Goodwill Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING PROFIT	6,603.1	5,124.2	5,359.5	3,670.8	2,636.1	4,258.2	5,910.7	7,690.1	5,263.0	3,716.5	3,864.6	6,366.1	60,462.9	5,948.5
Excep-Merger Costs-Non Oper	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exceptional-Other Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dividend Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE INTEREST & TAXES	6,603.1	5,124.2	5,359.5	3,670.8	2,636.1	4,258.2	5,910.7	7,690.1	5,263.0	3,716.5	3,864.6	6,366.1	60,462.9	5,948.5
Total External Interest	(1,709.9)	(1,717.5)	(1,746.2)	(1,273.8)	(1,272.2)	(1,331.7)	(1,296.4)	(1,274.4)	(1,289.7)	(1,324.9)	(1,358.1)	(1,322.6)	(16,917.5)	(1,271.0)
Total Internal Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Interest	(1,709.9)	(1,717.5)	(1,746.2)	(1,273.8)	(1,272.2)	(1,331.7)	(1,296.4)	(1,274.4)	(1,289.7)	(1,324.9)	(1,358.1)	(1,322.6)	(16,917.5)	(1,271.0)
PROFIT BEFORE TAX	8,313.0	6,841.7	7,105.7	4,944.6	3,908.3	5,589.9	7,207.1	8,964.5	6,552.7	5,041.5	5,222.7	7,688.7	77,380.4	7,219.5

Income Statement - YTD by Month
($ 000)

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Narragansett Electric Company
CY08 & CY09 (through March)
Budget
$000's

	CY 2008 JAN	CY 2008 FEB	CY 2008 MAR	CY 2008 APRIL	CY 2008 MAY	CY 2008 JUNE	CY 2008 JULY	CY 2008 AUG	CY 2008 SEPT	CY 2008 OCT	CY 2008 NOV	CY 2008 DEC	CY 2008 Annual	CY 2009 JAN
Total Taxes	2,522.9	2,522.9	2,522.9	2,167.1	2,167.1	2,167.1	2,167.1	2,167.1	2,167.1	2,167.1	2,167.1	2,167.1	27,072.5	2,167.1
Sh of Assoc/JV Post-Tax Profit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT AFTER TAXES	5,790.1	4,318.8	4,582.8	2,777.5	1,741.2	3,422.8	5,040.1	6,797.5	4,385.6	2,874.4	3,055.7	5,521.6	50,307.9	5,052.5
Minority Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Dividends	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT ATTRIB TO SHAREHOLDERS	5,790.1	4,318.8	4,582.8	2,777.5	1,741.2	3,422.8	5,040.1	6,797.5	4,385.6	2,874.4	3,055.7	5,521.6	50,307.9	5,052.5
Common Dividends	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RETAINED PROFIT	5,790.1	4,318.8	4,582.8	2,777.5	1,741.2	3,422.8	5,040.1	6,797.5	4,385.6	2,874.4	3,055.7	5,521.6	50,307.9	5,052.5

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Income Statement - YTD by Month
($ 000)

Narragansett Electric Company
CY08 & CY09 (through March)
Budget
$000's

	CY 2009 FEB	CY 2009 MAR	CY APRIL	CY MAY	CY JUNE	CY 2009 Year to Date
TOTAL OPERATING REVENUES	67,281.1	70,403.8	85,354.0	80,757.1	82,687.3	461,151.6
TOTAL OTHER INCOME	451.6	451.6	836.1	836.1	836.1	3,863.1
OTHER OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL INCOME	67,732.7	70,855.4	86,190.1	81,593.2	83,523.4	465,014.7
OPERATING EXPENSES						
Staff Costs						
Subtotal Payroll	3,514.7	3,539.3	3,903.9	3,673.0	3,759.4	22,223.2
Subtotal Benefits	1,789.1	1,798.9	3,999.5	4,000.1	4,011.1	17,383.3
Payroll Taxes	329.6	331.3	339.9	339.9	341.4	2,010.9
Subtotal Staff Costs	5,633.3	5,669.5	8,243.2	8,013.0	8,111.8	41,617.3
Other Expenses						
Other Expenses-Detail	4,452.7	6,552.5	3,953.7	4,091.5	4,156.2	28,285.8
Rents	314.9	314.9	353.6	336.6	336.5	1,971.3
Other Expenses-Other	1,095.2	1,291.5	4,473.3	1,659.0	2,909.6	13,075.8
Subtotal Other Expenses	5,862.7	8,158.8	8,780.6	6,087.1	7,402.4	43,332.9
Total Staff & Other Exp	11,496.1	13,828.3	17,023.7	14,100.1	15,514.2	84,950.2
Purchased Power - Electricity	45,609.5	48,050.7	56,702.6	56,702.6	56,702.6	314,362.7
Purchased Gas	0.0	0.0	0.0	0.0	0.0	0.0
Trans Credit from Affiliates	(2,979.2)	(2,979.2)	(3,641.7)	(2,712.2)	(3,016.7)	(18,308.4)
Total Wheeling	0.0	0.0	3,295.3	3,295.3	3,295.3	9,886.0
Total Depreciation Expense	3,685.0	4,783.2	4,011.5	4,014.0	4,016.4	24,180.9
Total Amortization Expense	24.6	24.6	0.0	0.0	0.0	73.8
Total Property Taxes / Rates	4,872.7	4,872.7	5,000.4	5,000.4	5,000.4	29,619.2
TOTAL OPERATING EXPENSES	62,708.6	68,580.2	82,391.8	80,400.1	81,512.3	444,764.5
OPERATING INCOME	5,024.1	2,275.2	3,798.3	1,193.1	2,011.1	20,250.2
Total Equity in Subsidiaries	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE GOODWILL	5,024.1	2,275.2	3,798.3	1,193.1	2,011.1	20,250.2
Goodwill Amortization	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING PROFIT	5,024.1	2,275.2	3,798.3	1,193.1	2,011.1	20,250.2
Excep-Merger Costs-Non Oper	0.0	0.0	0.0	0.0	0.0	0.0
Exceptional-Other Costs	0.0	0.0	0.0	0.0	0.0	0.0
Non Operating Income	0.0	0.0	0.0	0.0	0.0	0.0
Dividend Income	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT BEFORE INTEREST & TAXES	5,024.1	2,275.2	3,798.3	1,193.1	2,011.1	20,250.2
Total External Interest	(1,270.6)	(1,279.1)	(326.5)	(449.2)	(327.2)	(4,923.6)
Total Internal Interest	0.0	0.0	0.0	0.0	0.0	0.0
Net Interest	(1,270.6)	(1,279.1)	(326.5)	(449.2)	(327.2)	(4,923.6)
PROFIT BEFORE TAX	6,294.7	3,554.2	4,124.7	1,642.3	2,338.4	25,173.8

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Income Statement - YTD by Month
($ 000)

Narragansett Electric Company
CY08 & CY09 (through March)
Budget
$000's

	CY 2009 FEB	CY 2009 MAR	CY APRIL	CY MAY	CY JUNE	CY 2009 Year to Date
Total Taxes	2,167.1	2,167.1	2,198.7	1,243.7	1,551.1	11,494.7
Sh of Assoc/JV Post-Tax Profit	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT AFTER TAXES	4,127.6	1,387.1	1,926.1	398.5	787.3	13,679.1
Minority Interest	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Dividends	0.0	0.0	0.0	0.0	0.0	0.0
PROFIT ATTRIB TO SHAREHOLDERS	4,127.6	1,387.1	1,926.1	398.5	787.3	13,679.1
Common Dividends	0.0	0.0	0.0	0.0	0.0	0.0
RETAINED PROFIT	4,127.6	1,387.1	1,926.1	398.5	787.3	13,679.1

Narragansett Electric Company
CY08 & CY09 (through March)
Actuals
$000's

	CY 2008 JAN	CY 2008 FEB	CY 2008 MAR
TOTAL OPERATING REVENUES	10,178.2	10,127.0	15,522.0
TOTAL OTHER INCOME	72.4	125.6	425.2
OTHER OPERATING INCOME	0.0	0.0	0.0
TOTAL INCOME	10,250.6	10,252.6	15,947.1
OPERATING EXPENSES	0.0	0.0	0.0
Subtotal Staff Costs	(371.7)	686.6	804.7
Subtotal Other Expenses	351.0	1,077.5	6,146.2
Total Staff & Other Exp	(20.7)	1,764.1	6,950.9
Purchased Power - Electricity	8,416.4	8,382.3	8,992.9
Purchased Gas	0.0	0.0	0.0
Trans Credit from Affiliates	(686.6)	312.2	45.4
Total Wheeling	3,187.6	2,497.2	4,953.7
Total Depreciation Expense	64.8	66.5	71.8
Total Amortization Expense	(24.6)	(24.6)	(24.6)
Total Property Taxes / Rates	222.4	(320.7)	990.5
TOTAL OPERATING EXPENSES	11,159.4	12,676.9	21,980.5
OPERATING INCOME	(908.8)	(2,424.3)	(6,033.4)
Total Equity in Subsidiaries	0.0	0.0	0.0
PROFIT BEFORE GOODWILL	(908.8)	(2,424.3)	(6,033.4)
Goodwill Amortization	0.0	0.0	0.0
OPERATING PROFIT	(908.8)	(2,424.3)	(6,033.4)

Excep-Merger Costs-Non Oper	0.0	0.0	0.0
Exceptional-Other Costs	0.0	0.0	0.0
Non Operating Income	0.0	0.0	0.0
Dividend Income	0.0	0.0	0.0
PROFIT BEFORE INTEREST & TAXES	(908.8)	(2,424.3)	(6,033.4)
Total External Interest	2,202.2	2,157.1	2,583.6
Total Internal Interest	0.0	0.0	0.0
Net Interest	2,202.2	2,157.1	2,583.6
PROFIT BEFORE TAX	(3,111.0)	(4,581.4)	(8,617.0)
Total Taxes	(2,990.4)	(1,754.2)	(4,118.6)
Sh of Assoc/JV Post-Tax Profit	5,682.5	6,261.5	402.4
PROFIT AFTER TAXES	5,561.8	3,434.2	(4,095.9)
Minority Interest	0.0	0.0	0.0
Preferred Dividends	(93.6)	0.0	0.0
PROFIT ATTRIB TO SHAREHOLDERS	5,655.4	3,434.2	(4,095.9)
Common Dividends	0.0	0.0	0.0
RETAINED PROFIT	5,655.4	3,434.2	(4,095.9)

CY 2008 APRIL	CY 2008 MAY	CY 2008 JUNE	CY 2008 JULY	CY 2008 AUG	CY 2008 SEPT
14,702.3	50,481.7	25,709.4	56,650.9	26,607.4	23,258.7
123.3	163.7	424.3	(145.6)	150.3	223.9
0.0	0.0	0.0	0.0	0.0	0.0
14,825.6	50,645.4	26,133.7	56,505.3	26,757.7	23,482.6
0.0	0.0	0.0	0.0	0.0	0.0
(8.3)	(140.5)	360.0	(122.7)	1.6	1,095.4
(1,176.0)	513.5	1,267.2	1,384.8	1,832.3	6,033.2
(1,184.3)	373.0	1,627.2	1,262.1	1,833.9	7,128.6
8,599.0	37,021.1	20,010.4	41,681.3	20,329.3	17,684.6
0.0	0.0	0.0	0.0	0.0	0.0
(2,371.1)	931.5	238.5	(696.2)	(76.6)	(39.8)
6,405.4	13,196.7	5,093.3	6,884.0	7,944.0	7,963.6
94.7	108.7	115.1	121.8	134.0	(1,013.5)
(24.6)	(24.6)	(24.6)	(24.6)	(24.6)	(24.6)
(238.5)	1,196.3	276.0	1,947.3	725.0	838.9
11,280.6	52,802.7	27,335.9	51,175.7	30,865.0	32,537.8
3,545.0	(2,157.2)	(1,202.1)	5,329.6	(4,107.3)	(9,055.2)
0.0	0.0	0.0	0.0	0.0	0.0
3,545.0	(2,157.2)	(1,202.1)	5,329.6	(4,107.3)	(9,055.2)
0.0	0.0	0.0	0.0	0.0	0.0
3,545.0	(2,157.2)	(1,202.1)	5,329.6	(4,107.3)	(9,055.2)

0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
3,545.0	(2,157.2)	(1,202.1)	5,329.6	(4,107.3)	(9,055.2)
1,735.7	1,525.8	1,699.0	1,716.6	1,590.8	1,824.8
0.0	0.0	0.0	0.0	0.0	0.0
1,735.7	1,525.8	1,699.0	1,716.6	1,590.8	1,824.8
1,809.3	(3,683.0)	(2,901.2)	3,613.0	(5,698.1)	(10,880.0)
84.9	(2,212.2)	(1,294.4)	1,445.7	(1,249.6)	(3,688.3)
9,572.6	(9,972.4)	(2,560.1)	(3,021.3)	(1,410.2)	(5,336.8)
11,297.1	(11,443.3)	(4,166.9)	(854.0)	(5,858.7)	(12,528.6)
0.0	0.0	0.0	0.0	0.0	0.0
0.0	27.6	0.0	0.0	0.0	27.6
11,297.1	(11,470.9)	(4,166.9)	(854.0)	(5,858.7)	(12,556.2)
0.0	0.0	0.0	0.0	0.0	0.0
11,297.1	(11,470.9)	(4,166.9)	(854.0)	(5,858.7)	(12,556.2)

CY 2008 OCT	CY 2008 NOV	CY 2008 DEC	CY 2008 Annual	CY 2009 JAN
25,021.8	27,627.4	20,040.4	305,927.1	21,865.2
221.1	104.2	1,845.2	3,733.7	168.8
0.0	0.0	0.0	0.0	0.0
25,242.9	27,731.6	21,885.6	309,660.8	22,034.0
0.0	0.0	0.0	0.0	0.0
241.2	(379.2)	(502.8)	1,664.2	(75.7)
(1,473.5)	(240.4)	(712.7)	15,003.2	(95.2)
(1,232.3)	(619.6)	(1,215.5)	16,667.4	(170.9)
18,790.2	19,356.4	13,698.7	222,962.5	19,311.7
0.0	0.0	0.0	0.0	0.0
(1,025.3)	(537.7)	305.7	(3,600.0)	1,139.7
8,073.4	7,362.3	6,281.2	79,842.6	6,288.7
142.1	129.8	128.3	164.0	126.9
(24.6)	(24.6)	(24.6)	(295.2)	(24.6)
501.4	630.2	690.2	7,459.0	590.9
25,224.9	26,296.8	19,864.0	323,200.3	27,262.5
18.0	1,434.8	2,021.6	(13,539.5)	(5,228.5)
0.0	0.0	0.0	0.0	0.0
18.0	1,434.8	2,021.6	(13,539.5)	(5,228.5)
0.0	0.0	0.0	0.0	0.0
18.0	1,434.8	2,021.6	(13,539.5)	(5,228.5)

0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0
18.0	1,434.8	2,021.6	(13,539.5)	(5,228.5)
1,903.8	1,703.7	1,788.4	22,431.5	1,691.1
0.0	0.0	0.0	0.0	0.0
1,903.8	1,703.7	1,788.4	22,431.5	1,691.1
(1,885.8)	(268.9)	233.1	(35,971.0)	(6,919.6)
(905.1)	(76.7)	(643.9)	(17,402.7)	(2,107.8)
(524.9)	943.2	8,880.3	8,916.7	5,478.8
(1,505.6)	751.0	9,757.3	(9,651.6)	667.1
0.0	0.0	0.0	0.0	0.0
0.0	27.6	0.0	(10.8)	0.0
(1,505.6)	723.4	9,757.3	(9,640.8)	667.1
0.0	0.0	0.0	0.0	0.0
(1,505.6)	723.4	9,757.3	(9,640.8)	667.1

CY 2009 FEB	CY 2009 MAR	CY 2009 APR	CY 2009 MAY	CY 2009 JUN	CY 2009 Year to Date
14,770.8	4,404.9	(13,774.0)	(9,923.8)	(11,012.7)	6,330.4
82.4	(1,793.9)	(186.0)	(278.4)	(165.3)	(2,172.4)
0.0	0.0	0.0	0.0	0.0	0.0
14,853.2	2,611.0	(13,960.0)	(10,202.2)	(11,178.0)	4,158.0
0.0	0.0	0.0	0.0	0.0	
(79.1)	1,819.6	(1,835.4)	(692.1)	680.2	(182.4)
2,174.9	7,973.7	(3,305.3)	(213.9)	801.5	7,335.7
2,095.9	9,793.4	(5,140.7)	(906.0)	1,481.7	7,153.3
9,276.7	(5,020.9)	(10,526.3)	(12,995.7)	(13,672.3)	(13,626.8)
0.0	0.0	0.0	0.0	0.0	0.0
(916.7)	(2,163.1)	(2,125.9)	968.2	(417.1)	(3,514.9)
7,454.6	8,079.6	3,560.0	2,806.5	3,396.6	31,586.0
124.4	(960.2)	(176.7)	(169.8)	(162.3)	(1,217.7)
(24.6)	(24.6)	0.0	0.0	0.0	(73.8)
79.3	(357.7)	(342.4)	(328.6)	(327.5)	(686.0)
18,089.6	9,346.5	(14,752.0)	(10,625.5)	(9,700.9)	19,620.1
(3,236.4)	(6,735.5)	792.0	423.2	(1,477.1)	(15,462.1)
0.0	0.0	0.0	0.0	0.0	0.0
(3,236.4)	(6,735.5)	792.0	423.2	(1,477.1)	(15,462.1)
0.0	0.0	0.0	0.0	0.0	0.0
(3,236.4)	(6,735.5)	792.0	423.2	(1,477.1)	(15,462.1)

0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
(3,236.4)	(6,735.5)	792.0	423.2	(1,477.1)	(15,462.1)
1,637.2	1,627.3	657.9	757.4	547.0	6,917.9
0.0	0.0	0.0	0.0	0.0	0.0
1,637.2	1,627.3	657.9	757.4	547.0	6,917.9
(4,873.6)	(8,362.8)	134.1	(334.1)	(2,024.0)	(22,380.0)
(2,018.5)	(4,227.8)	(1,373.1)	(305.7)	(1,740.2)	(11,773.1)
10,116.7	(1,090.9)	842.6	(981.3)	(4,769.3)	9,596.6
7,261.5	(5,225.9)	2,349.8	(1,009.7)	(5,053.1)	(1,010.3)
0.0	0.0	0.0	0.0	0.0	0.0
27.6	0.0	0.0	0.0	27.6	55.2
7,233.9	(5,225.9)	2,349.8	(1,009.7)	(5,080.7)	(1,065.5)
0.0	0.0	0.0	0.0	0.0	0.0
7,233.9	(5,225.9)	2,349.8	(1,009.7)	(5,080.7)	(1,065.5)

THE NARRAGANSETT ELECTRIC COMPANY
Statements of Cash Flows
Twleve Months Ended March 31
(In thousands)
(Unaudited)

	2009	2008
Operating activities:		
Net income	$ 31,003	$ 41,405
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	66,274	64,364
Deferred income taxes and investment tax credits, net	39,486	10,230
Allowance for funds used during construction	(23)	(296)
Rate adjustment mechanisms	(36,191)	(16,974)
Changes in assets and liabilities:		
Accounts receivable, net and unbilled revenues	20,762	(35,426)
Accounts receivable - affiliates	1,848	(1,848)
Materials and supplies	7,332	(4,340)
Prepayments	(2,944)	1,056
Regulatory assets	(7,047)	6,687
Accounts payable	(44,026)	20,681
Accounts payable - affiliates	2,582	(13,897)
Accrued expenses	(13,940)	(5,103)
Other current liabilities	(1,100)	6,672
Pension and other postretirement benefits	(7,608)	(12,254)
Other reserves and deferred credits	(1,790)	466
Other, net	4,131	4,036
Net cash provided by operating activities	58,749	65,459
Investing activities:		
Plant expenditures	(121,925)	(119,444)
Change in restricted cash	(83,705)	10,224
Other investing activities	(7,483)	704
Net cash used in investing activities	(213,113)	(108,516)
Financing activities:		
Capital contributed from parent	-	60,000
Dividends paid	-	(33)
Preferred stock-retirements	-	(2,974)
Reductions in long-term debt	(6,645)	(11,673)
Changes in short-term debt and money pool, net	170,000	(23,400)
Net cash provided by financing activities	163,355	21,920
Net increase/(decrease) in cash and cash equivalents	8,991	(21,137)
Cash and cash equivalents at beginning of period	8,641	29,778
Cash and cash equivalents at end of period	$ 17,632	$ 8,641
Supplementary information:		
Interest paid, less amounts capitalized	$ 10,175	$ 12,542
Federal and state income taxes paid to/(refunded from) parent	$ (13,398)	$ 12,014

NATIONAL GRID USA MONEY POOL
NARRAGANSETT ELECTRIC COMPANY
Month End Short Term Debt Balances

		Money Pool	Expense	Rate	Prime Rate	Open Acct Advance	Rate
		(a)	(b)	(c)	(d)	(e)	(f)
(1)	JANUARY 08	$73,650,000	$192,870	4.12%	6.00%	0	N/A
(2)	FEBRUARY 08	$66,500,000	$149,284	3.85%	6.00%	0	N/A
(3)	MARCH 08	$89,625,000	$145,424	3.23%	5.25%	0	N/A
(4)	APRIL 08	$71,475,000	$160,385	2.84%	5.00%	0	N/A
(5)	MAY 08	$45,650,000	$89,644	2.58%	5.00%	0	N/A
(6)	JUNE 08	$54,825,000	$76,766	2.46%	5.00%	0	N/A
(7)	JULY 08	$99,500,000	$134,587	2.45%	5.00%	0	N/A
(8)	AUGUST 08	$134,525,000	$222,403	2.44%	5.00%	0	N/A
(9)	SEPTEMBER 08	$75,800,000	$253,110	3.47%	5.00%	$50,000,000	N/A
(10)	OCTOBER 08	$98,375,000	$300,979	4.52%	4.00%	$50,000,000	N/A
(11)	NOVEMBER 08	$147,475,000	$178,015	1.88%	4.00%	$50,000,000	N/A
(12)	DECEMBER 08	$119,400,000	$115,479	1.18%	3.25%	$100,000,000	N/A
(13)	JANUARY 09	$122,075,000	$57,876	0.57%	3.25%	$130,000,000	N/A
(14)	FEBRUARY 09	$124,800,000	$54,158	0.76%	3.25%	$130,000,000	N/A
(15)	MARCH 09	$129,625,000	$64,557	0.69%	3.25%	$130,000,000	N/A
(16)	APRIL 09	$126,825,000	$41,738	0.48%	3.25%	$130,000,000	N/A
(17)	MAY 09	$131,600,000	$31,470	0.38%	3.25%	$100,000,000	N/A

Division Data Request 5-A

Request:

A. Historical Charge-Off Data Request

Time period:	2007, 2008 & YTDMay 2009
Type of accounts:	Rhode Island-based accounts charged off in 2007, 2008 and YTDMay 2009
Data Volume:	All accounts charged off
File Format:	Comma or tab delimited ASCII text file (.csv, .txt) or MS Excel worksheet
File Key:	Detailed written explanation of each header, codes and data as noted below
Data Delivery:	TBD – secure FTP website, Compact Disk or email

Data Fields (i.e., Headers)

1. Rate Code (See Exhibit A, attached)
   a. Minimum: residential vs. non-residential
2. Service Analysis (See Exhibit B, attached)
   a. Minimum: residential vs. non-residential
3. Customer Name
   a. Full name in one field (i.e., first and last name not in separate fields)
   b. Example: WILLIAM F. LONG
4. Account Number
   a. Full account number, including explanation of any number sequencing which may identify location (i.e., city code) or number of accounts from the same accountholder
5. Account Status
   a. Active or inactive account as of the time of the data pull

Prepared by or under the supervision of: Rudy L. Wynter

Division Data Request 5-A (cont.)

6. Turn on Date

   a. Original date accountholder started service
   b. Example: 01/01/2007

7. Turn Off Date

   a. Date of accountholder ended service (i.e., start of inactive status)
   b. Example: 01/01/2007

8. Turnoff Balance

   a. Total balance due at the time of turn off (current plus all past due dollars)
   b. Alternative would be total due at final bill, subsequent to turn off date

9. Charge Off Date

   a. Date company wrote off account as "uncollectible"
   b. Example: 01/01/2007

10. Charge Off Balance

    a. Total dollars charged off on the charge off date

11. Last Payment Date

    a. Last payment received on account
    b. Example: 01/01/2007

12. Last Payment Amount

    a. Total dollars received on the last payment date

13. Current Account Balance

    a. Total balance due on account on the date of the data pull

Prepared under the supervision of: Rudy L. Wynter

Division Data Request 5-A (cont.)

14. Additional flags on accounts, including:

   a. Bankruptcy
   b. Deceased
   c. Protected status, with additional detail, if available:
      i. Elderly
      ii. Low income
      iii. Medical
      iv. Financial

15. Disconnection Code

   a. Reason for disconnection
   b. Examples:
      i. SONP – shut off non-payment
      ii. Customer request – closed voluntarily
      iii. Etc.

16. Meter location

   a. Example: “outside,” “Basement,” “inside,” etc.

   b. Include meter location data only if access issues prevent disconnections for non-payment (i.e., CGI – can’t get in)

Response:

Attachment DIV 5-A (1) through (3) are three spreadsheets presenting the requested data.

Please note that the last column of the spreadsheets provided as DIV-5-A-2 (2007) and DIV-5-A-3 (2008 and 2009) contains the disconnection code.

For disconnection codes, the file **DIV 5-A-2 (2007).xls**, uses the heading 'Crdt Actn Cd' (a CIS header). An indicator of "8", "9" or "A" was translated as CONP for the conversion of the CIS data to CSS during Project One. All other codes are shown as "OTH" -- 'other'.

Division Data Request 5-A (cont.)

For disconnection codes in the file DIV 5-A-3 (2008 and 2009).xls, the heading 'CD COLL ACTVTY' (a CSS header) is used. There is only one CONP indicator for CONP and that is "085".

Please note that the "CONP" percentage of all writeoffs listed on each file is substantially understated in reality. Many (if not most) of the "blanks" in the new columns on each file likely represent a meter that was finaled and written off because a new tenant/owner requested service at a premise that was abandoned (with arrears). In many cases, the Company is not aware that a premise has been vacated until new service is requested by the next owner. However, this type of field visit would not be coded as "CONP."

Also, please note that the electronic spreadsheets provided as DIV-5-A-2 (2007) and DIV 5-A-3 (2008 and 2009) contain confidential customer names and accounts. Therefore, the Company is submitting a redacted version of the electronic spreadsheets for inclusion in the public record. Confidential versions will be provided to the Commission and the Division along with a Motion for Protective Treatment.

Prepared under the supervision of: Rudy L. Wynter

Division Data Request 5-B

Request:

B. Historical Accounts Receivable (Arrears) Data

Time period:	Monthly for 2007, 2008 & YTDMay 2009
Type of accounts:	Rhode Island-based accounts by AR bucket
Data Type:	Unique dollars and number of accounts (also called total "indebtedness") in each A/R bucket (i.e., 0-30, 31-60, 61-90…>360) for the following types of customers: (1) residential (standard customers-non-protected), (2) residential protected class and (3) non-residential
File Format:	MS Excel worksheet
File Key:	N/A
Data Delivery:	TBD – secure FTP website, Compact Disk or email

A spreadsheet example is attached as Exhibit C. "indebtedness" shows the unique dollars and number of accounts in each A/R bucket. For example, in a 90-day bucket (91-120 days past due) the total dollars due should show only the dollars and accounts that are aged in that bucket. It should not include any dollars from earlier buckets or current bills.

Response:

Please see Attachment DIV 5-B for the requested information in the years 2008 and 2009. Please note that the Company is continuing to work on the data collection for 2007 and will supplement this response when it is available.

Prepared by or under the supervision of: Rudy L. Wynter

NARRAGANSETT ELECTRIC -- ACCOUNTS RECEIVABLE BY 30 DAY BUCKET
JANUARY 2008 - MAY 2009

Res Comm	Protected	Month	0 - 30	31 - 60	61 - 90	91 - 120	121 - 150	151 - 180	181 - 210	211 - 240	241 - 270	271 - 300	301 - 330	331 - 360	Over 360	Total
R	N	200801	25,874,996	7,045,351	3,136,164	2,400,240	1,817,944	1,553,624	897,252	532,215	372,236	338,509	303,055	212,741	963,270	45,447,595
R	N	200802	26,946,836	7,136,300	4,301,622	2,074,820	1,627,436	1,381,396	1,164,836	682,648	400,803	307,027	282,663	244,535	1,039,814	47,590,736
R	N	200803	25,013,076	7,697,044	4,274,623	2,675,646	1,453,615	1,118,505	1,027,429	832,708	500,510	326,967	234,010	222,484	1,083,833	46,460,448
R	N	200804	23,432,859	7,273,388	4,457,960	3,039,815	1,816,838	940,198	847,033	783,822	674,598	359,645	268,748	190,626	1,125,150	45,210,680
R	N	200805	18,120,006	6,587,819	4,370,325	2,927,913	1,761,235	1,342,015	716,557	604,127	544,191	484,531	306,342	193,670	1,127,094	39,085,823
R	N	200806	22,890,642	4,816,896	3,758,141	2,507,418	1,888,367	1,279,537	897,485	525,543	435,837	417,952	362,489	230,923	1,089,831	41,101,060
R	N	200807	27,815,793	6,461,654	2,562,343	2,152,305	1,662,836	1,372,196	970,697	661,935	413,742	355,634	329,479	290,949	1,148,870	46,198,433
R	N	200808	38,202,102	5,534,809	2,754,369	1,462,248	1,381,238	1,076,746	913,745	664,361	455,489	285,210	250,614	231,850	1,115,448	54,328,229
R	N	200809	33,156,994	8,948,876	2,289,147	1,602,134	931,611	877,523	759,683	598,616	408,426	311,630	193,129	183,639	994,958	51,256,365
R	N	200810	23,673,756	8,163,358	3,934,038	1,597,566	992,081	654,065	658,611	482,048	428,013	331,888	225,776	131,432	951,962	42,224,595
R	N	200811	26,780,808	6,092,433	3,998,371	2,470,199	933,291	739,759	481,166	470,066	377,899	331,794	238,621	176,328	873,504	43,964,239
R	N	200812	28,869,161	7,322,725	3,587,668	2,517,358	1,822,654	1,015,479	607,303	347,645	394,612	326,665	266,985	220,474	929,234	48,227,966
R	N	200901	35,095,402	6,927,934	3,339,332	2,208,183	1,718,331	1,291,867	740,516	454,204	269,028	309,366	261,609	215,816	980,893	53,812,480
R	N	200902	26,530,750	8,826,502	3,137,647	2,128,467	1,474,486	1,095,961	945,434	520,935	312,289	200,614	238,200	186,082	891,274	46,488,641
R	N	200903	21,961,285	7,232,125	4,238,907	2,072,993	1,288,782	1,008,203	843,295	621,794	410,077	238,756	157,483	167,613	840,798	41,082,110
R	N	200904	22,276,677	5,668,006	3,469,585	2,634,346	1,358,607	870,644	691,469	590,546	446,463	306,494	180,849	119,734	824,119	39,437,540
R	N	200905	20,634,311	5,329,562	2,772,664	2,038,159	1,705,257	829,696	619,810	483,833	400,451	342,541	219,710	142,266	765,499	36,283,758
R	Y	200801	2,786,884	1,526,900	954,647	885,453	750,591	762,209	524,058	368,161	295,756	307,005	291,995	231,656	1,615,695	11,301,010
R	Y	200802	3,000,378	1,495,290	1,256,658	759,111	726,175	658,744	653,892	448,692	311,024	273,502	275,296	251,467	1,730,861	11,841,088
R	Y	200803	2,768,887	1,663,590	1,227,796	973,316	634,645	609,816	581,557	548,398	382,866	286,897	232,485	238,169	1,823,440	11,971,862
R	Y	200804	2,636,594	1,569,550	1,282,437	1,093,775	828,596	511,834	549,729	511,247	506,440	325,370	264,231	213,370	1,912,681	12,205,853
R	Y	200805	1,967,071	1,412,049	1,315,955	1,114,180	828,820	751,009	469,425	485,303	424,694	427,914	302,385	211,340	1,842,973	11,553,118
R	Y	200806	2,401,569	1,057,727	1,212,098	1,015,722	921,967	742,167	610,858	406,214	405,768	382,765	361,818	258,339	1,857,697	11,634,708
R	Y	200807	2,918,804	1,353,483	875,012	922,183	834,646	819,932	669,248	508,881	352,817	372,283	320,291	315,402	1,920,430	12,183,414
R	Y	200808	4,324,273	1,321,995	996,306	705,894	774,160	716,012	708,843	577,592	441,454	309,882	323,432	281,350	1,997,766	13,478,957
R	Y	200809	3,708,608	2,200,846	959,634	842,134	593,129	634,549	659,592	601,488	460,067	387,695	273,263	278,105	1,965,917	13,565,025
R	Y	200810	2,832,063	1,981,264	1,671,169	920,785	672,914	533,271	618,512	531,098	523,208	460,084	336,589	214,500	2,042,600	13,338,057
R	Y	200811	3,469,672	1,440,832	1,638,622	1,432,394	683,709	626,601	516,688	536,817	494,630	482,881	392,614	305,269	2,076,818	14,097,547
R	Y	200812	3,632,073	1,943,160	1,422,207	1,330,737	1,231,833	814,880	571,442	394,578	507,640	468,490	417,868	385,203	2,261,913	15,382,022
R	Y	200901	4,600,032	2,016,504	1,548,372	1,210,725	1,156,526	1,085,784	727,327	509,388	350,752	450,710	413,629	367,649	2,273,723	16,711,124
R	Y	200902	3,626,057	2,753,628	1,599,955	1,360,071	1,048,627	941,941	983,556	642,469	446,439	331,329	415,911	365,167	2,418,692	16,933,843
R	Y	200903	3,038,235	2,321,245	2,363,994	1,508,029	1,107,069	922,295	916,738	817,711	593,498	407,929	306,695	344,857	2,561,775	17,210,072
R	Y	200904	3,090,548	1,891,244	1,934,048	2,016,512	1,314,059	967,160	831,087	819,242	731,304	530,964	364,367	275,650	2,673,541	17,439,726
R	Y	200905	2,837,625	1,817,375	1,653,742	1,660,472	1,732,958	1,044,624	875,984	737,273	705,892	667,900	456,244	328,832	2,613,222	17,132,145
C	N	200801	39,420,379	5,937,035	1,596,202	772,331	369,302	360,463	235,460	189,315	165,304	153,759	119,857	67,613	378,404	49,765,424
C	N	200802	43,876,084	8,727,708	2,507,717	800,332	395,601	283,724	282,285	209,828	141,353	120,699	98,958	66,484	419,936	57,930,710
C	N	200803	40,471,690	8,144,650	4,404,830	1,468,953	472,308	279,725	229,873	188,824	166,669	110,763	98,957	74,164	353,533	56,464,940
C	N	200804	41,280,791	7,783,720	3,204,956	1,338,690	370,772	236,942	214,460	184,864	161,734	139,173	98,577	75,902	375,219	55,465,801
C	N	200805	33,526,078	8,690,006	2,585,323	1,257,697	639,102	265,114	234,426	195,340	149,880	151,164	140,888	90,400	444,996	48,370,415
C	N	200806	37,823,461	6,730,182	2,270,931	1,142,193	636,565	409,545	189,384	202,280	172,160	139,714	129,881	133,547	517,609	50,497,453
C	N	200807	35,857,838	7,936,760	1,819,731	910,079	808,586	484,239	343,772	141,318	165,941	153,323	135,980	121,830	621,806	49,501,203
C	N	200808	49,135,835	5,342,297	2,024,558	762,230	539,153	606,788	396,593	261,963	97,095	133,223	121,138	110,202	697,404	60,228,478
C	N	200809	58,755,426	7,521,231	1,163,669	1,055,030	466,273	389,492	471,396	326,278	148,509	77,010	76,179	65,479	440,814	70,956,786
C	N	200810	58,613,024	12,054,218	1,688,547	512,344	414,420	283,919	259,628	356,493	283,749	117,884	61,566	77,291	485,358	75,208,439
C	N	200811	42,017,370	8,003,979	1,707,956	747,606	269,100	326,808	164,532	159,441	326,024	232,485	91,481	47,905	412,278	54,506,966
C	N	200812	38,499,689	9,068,165	2,615,162	786,381	566,865	259,901	229,713	183,612	136,415	314,690	220,262	90,530	459,696	53,431,082
C	N	200901	45,925,525	7,804,280	2,049,703	1,065,859	544,229	453,555	193,920	147,376	150,192	110,968	293,720	202,573	440,413	59,382,315
C	N	200902	39,331,184	7,208,535	1,401,002	839,166	529,789	323,612	339,537	127,107	105,965	125,906	69,603	259,554	462,889	51,123,849
C	N	200903	31,794,918	7,772,480	1,718,915	653,589	485,723	382,349	219,470	135,535	97,431	77,191	50,378	42,214	670,785	44,100,977
C	N	200904	31,374,450	5,531,553	1,744,262	827,694	383,397	329,514	268,835	162,313	96,903	71,703	60,217	35,575	689,716	41,576,131
C	N	200905	32,938,682	5,554,172	1,413,046	762,626	449,452	237,520	189,981	139,530	83,182	75,976	51,991	40,153	661,945	42,598,258
Total A/R		200801	68,082,259	14,509,285	5,687,013	4,058,024	2,937,836	2,676,296	1,656,770	1,089,692	833,295	799,274	714,906	512,009	2,957,369	106,514,028
		200802	73,823,297	17,359,297	8,065,997	3,634,263	2,749,212	2,323,864	2,101,013	1,341,167	853,180	701,228	656,917	562,487	3,190,611	117,362,534
		200803	68,253,653	17,505,284	9,907,249	5,117,914	2,560,568	2,008,047	1,838,859	1,569,931	1,050,045	724,628	565,451	534,816	3,260,805	114,897,250
		200804	67,350,244	16,626,658	8,945,353	5,472,279	3,016,206	1,688,974	1,611,222	1,479,933	1,342,772	824,188	631,556	479,898	3,413,050	112,882,334
		200805	53,613,155	16,689,874	8,271,604	5,299,790	3,229,156	2,358,137	1,420,407	1,284,769	1,118,765	1,063,609	749,615	495,411	3,415,062	99,009,356
		200806	63,115,672	12,604,804	7,241,170	4,665,333	3,446,899	2,431,249	1,697,728	1,134,037	1,013,764	940,431	854,188	622,809	3,465,138	103,233,221
		200807	66,592,435	15,751,898	5,257,085	3,984,568	3,306,068	2,676,367	1,983,718	1,312,134	932,500	881,241	785,750	728,181	3,691,106	107,883,051
		200808	91,662,210	12,199,102	5,775,232	2,930,372	2,694,551	2,399,545	2,019,181	1,503,915	994,038	728,315	695,184	623,403	3,810,618	128,035,665
		200809	95,621,028	18,670,954	4,412,449	3,499,298	1,991,013	1,901,563	1,890,671	1,526,382	1,017,001	776,335	542,571	527,223	3,401,689	135,778,176
		200810	85,118,843	22,198,840	7,293,754	3,030,695	2,079,415	1,471,255	1,536,751	1,369,638	1,234,970	909,856	623,931	423,222	3,479,920	130,771,090
		200811	72,267,850	15,537,243	7,344,949	4,650,199	1,886,100	1,693,168	1,162,386	1,166,325	1,198,553	1,047,160	722,717	529,503	3,362,600	112,568,752
		200812	71,000,923	18,334,050	7,625,036	4,634,476	3,621,352	2,090,260	1,408,458	925,835	1,038,667	1,109,845	905,115	696,208	3,650,843	117,041,069
		200901	85,620,958	16,748,718	6,937,408	4,484,767	3,419,086	2,831,206	1,661,763	1,110,968	769,972	871,045	968,959	786,038	3,695,029	129,905,918
		200902	69,487,991	18,788,665	6,138,604	4,327,704	3,052,901	2,361,515	2,268,528	1,290,511	864,692	657,849	723,715	810,803	3,772,855	114,546,333
		200903	56,794,437	17,325,850	8,321,817	4,234,610	2,881,574	2,312,848	1,979,503	1,575,040	1,101,005	723,876	514,557	554,685	4,073,358	102,393,160
		200904	56,741,675	13,090,804	7,147,895	5,478,552	3,056,064	2,167,318	1,791,391	1,572,102	1,274,670	909,161	605,432	430,960	4,187,375	98,453,398
		200905	56,410,618	12,701,109	5,839,453	4,461,257	3,887,668	2,111,840	1,685,775	1,360,636	1,189,525	1,086,416	727,946	511,251	4,040,666	96,014,160

NARRAGANSETT ELECTRIC -- COUNT OF ACCOUNTS IN OLDEST 30 DAY BUCKET
JANUARY 2008 - MAY 2009

Res Comm	Protected	Month	0 - 30	31 - 60	61 - 90	91 - 120	121 - 150	151 - 180	181 - 210	211 - 240	241 - 270	271 - 300	301 - 330	331 - 360	Over 360	Total
R	N	200801	169,111	35,513	13,614	9,272	6,249	5,932	3,632	2,180	1,448	1,197	1,023	696	2,575	252,442
R	N	200802	188,195	33,009	17,744	8,425	6,019	4,686	4,256	2,601	1,583	1,150	930	786	2,829	272,213
R	N	200803	188,719	34,877	16,473	10,036	5,777	3,952	3,474	2,836	1,845	1,177	837	657	2,966	273,626
R	N	200804	189,865	33,388	17,134	10,713	6,603	3,432	2,851	2,565	2,198	1,270	931	672	3,026	274,648
R	N	200805	173,975	35,217	18,087	10,856	6,139	4,607	2,529	2,013	1,706	1,502	1,029	642	3,031	261,333
R	N	200806	189,492	31,477	16,854	9,461	6,677	4,205	2,849	1,730	1,401	1,196	1,078	764	2,968	270,152
R	N	200807	175,356	40,803	14,067	8,151	5,487	4,322	2,694	1,857	1,200	1,008	828	825	3,128	259,726
R	N	200808	194,919	32,734	15,292	6,537	4,556	3,314	2,807	1,705	1,232	802	712	597	2,841	268,048
R	N	200809	202,229	44,247	12,103	7,010	3,608	2,734	2,287	1,777	1,103	844	531	531	2,381	281,385
R	N	200810	176,161	44,170	18,127	6,823	3,965	2,515	2,093	1,405	1,232	867	578	331	2,273	260,540
R	N	200811	195,406	35,595	18,512	9,533	3,709	3,008	1,870	1,443	1,082	932	563	425	1,992	274,070
R	N	200812	175,039	40,999	17,053	9,632	6,444	3,758	2,440	1,371	1,224	872	713	532	2,086	262,163
R	N	200901	195,998	34,672	14,479	8,034	5,950	4,288	2,670	1,816	1,043	886	667	534	2,134	273,171
R	N	200902	188,775	39,721	12,198	7,013	4,699	3,656	3,068	1,915	1,264	808	641	508	1,937	266,203
R	N	200903	171,220	39,183	15,494	6,114	3,778	2,968	2,802	1,959	1,488	1,012	671	485	1,921	249,095
R	N	200904	185,216	32,726	14,978	7,732	3,727	2,444	2,097	2,058	1,425	1,117	802	558	1,934	256,814
R	N	200905	196,952	35,107	13,258	6,879	4,466	2,083	1,671	1,540	1,447	1,142	805	674	2,005	268,029
R	Y	200801	14,622	4,592	2,564	2,076	1,650	1,653	1,200	804	654	588	597	434	2,368	33,802
R	Y	200802	16,672	4,133	3,012	1,823	1,576	1,393	1,327	989	614	572	491	516	2,469	35,587
R	Y	200803	16,599	4,666	2,820	2,048	1,430	1,220	1,123	1,049	821	564	437	418	2,600	35,795
R	Y	200804	17,021	4,476	2,756	2,209	1,616	1,067	1,045	953	953	649	493	400	2,706	36,344
R	Y	200805	15,549	4,368	3,100	2,217	1,615	1,368	969	872	791	815	593	379	2,658	35,294
R	Y	200806	16,860	3,900	3,052	2,102	1,708	1,367	1,108	830	709	693	665	509	2,602	36,105
R	Y	200807	16,202	5,170	2,555	1,966	1,481	1,330	1,164	877	670	641	535	541	2,711	35,843
R	Y	200808	18,289	4,792	2,952	1,572	1,375	1,109	1,157	969	728	547	528	457	2,826	37,301
R	Y	200809	17,938	6,837	2,620	1,769	1,142	982	1,033	956	741	642	462	441	2,807	38,370
R	Y	200810	15,819	6,154	4,161	1,978	1,177	916	933	843	815	717	532	343	2,890	37,278
R	Y	200811	17,476	4,445	3,980	2,944	1,350	1,060	797	795	736	710	591	458	2,928	38,270
R	Y	200812	15,452	5,404	3,441	2,829	2,380	1,471	989	642	741	695	592	552	3,135	38,323
R	Y	200901	16,861	4,885	3,303	2,397	2,148	1,948	1,282	869	548	635	626	535	3,217	39,254
R	Y	200902	16,346	5,599	2,944	2,317	1,807	1,647	1,620	1,064	747	513	554	534	3,371	39,063
R	Y	200903	15,335	5,067	3,853	2,395	1,599	1,451	1,557	1,346	951	679	489	488	3,458	38,668
R	Y	200904	16,399	4,412	3,298	2,874	1,860	1,299	1,268	1,410	1,193	868	612	445	3,540	39,478
R	Y	200905	17,645	4,812	2,844	2,253	2,145	1,399	1,092	1,155	1,182	1,110	750	576	3,495	40,458
C	N	200801	31,698	8,265	2,042	1,002	449	286	176	143	89	69	56	50	218	44,543
C	N	200802	34,489	7,858	2,768	1,058	615	337	205	139	117	79	59	50	241	48,015
C	N	200803	30,536	8,414	4,027	1,373	667	393	264	165	118	101	62	49	259	46,428
C	N	200804	30,947	6,073	4,535	1,429	733	324	251	190	121	90	94	51	265	45,103
C	N	200805	30,105	8,871	2,400	1,450	696	471	246	190	157	114	84	82	301	45,167
C	N	200806	31,903	7,757	2,632	987	682	419	297	200	147	146	103	77	353	45,703
C	N	200807	27,690	8,325	2,876	1,000	529	385	286	220	160	109	123	86	390	42,179
C	N	200808	31,232	6,444	2,868	775	477	296	225	193	159	114	88	101	404	43,376
C	N	200809	33,293	7,665	1,826	822	415	297	205	162	145	120	94	68	430	45,542
C	N	200810	29,624	9,168	2,246	699	441	262	205	124	136	112	96	64	459	43,636
C	N	200811	32,817	7,438	2,209	774	346	279	178	131	99	100	89	77	446	44,983
C	N	200812	30,470	7,770	2,709	941	518	312	199	131	109	86	77	83	479	43,884
C	N	200901	32,479	7,622	2,354	922	507	332	234	159	104	95	74	65	484	45,431
C	N	200902	32,738	7,673	2,000	839	441	286	237	154	107	93	72	52	459	45,151
C	N	200903	28,811	8,937	2,233	884	412	306	228	156	118	89	65	61	462	42,762
C	N	200904	31,162	6,585	2,830	835	438	267	229	160	124	83	64	56	465	43,298
C	N	200905	33,649	7,196	1,873	963	423	263	209	172	103	106	61	49	475	45,542
Total Number Accounts		200801	215,431	48,370	18,220	12,350	8,348	7,871	5,008	3,127	2,191	1,854	1,676	1,180	5,161	330,787
		200802	239,356	45,000	23,524	11,306	8,210	6,416	5,788	3,729	2,314	1,801	1,480	1,352	5,539	355,815
		200803	235,854	47,957	23,320	13,457	7,874	5,565	4,861	4,050	2,784	1,842	1,336	1,124	5,825	355,849
		200804	237,833	43,937	24,425	14,351	8,952	4,823	4,147	3,708	3,272	2,009	1,518	1,123	5,997	356,095
		200805	219,629	48,456	23,587	14,523	8,450	6,446	3,744	3,075	2,654	2,431	1,706	1,103	5,990	341,794
		200806	238,255	43,134	22,538	12,550	9,067	5,991	4,254	2,760	2,257	2,035	1,846	1,350	5,923	351,960
		200807	219,248	54,298	19,498	11,117	7,497	6,037	4,144	2,954	2,030	1,758	1,486	1,452	6,229	337,748
		200808	244,440	43,970	21,112	8,884	6,408	4,719	4,189	2,867	2,119	1,463	1,328	1,155	6,071	348,725
		200809	253,460	58,749	16,549	9,601	5,165	4,013	3,525	2,895	1,989	1,606	1,087	1,040	5,618	365,297
		200810	221,604	59,492	24,534	9,500	5,583	3,693	3,231	2,372	2,183	1,696	1,206	738	5,622	341,454
		200811	245,699	47,478	24,701	13,251	5,405	4,347	2,845	2,369	1,917	1,742	1,243	960	5,366	357,323
		200812	220,961	54,173	23,203	13,402	9,342	5,541	3,628	2,144	2,074	1,653	1,382	1,167	5,700	344,370
		200901	245,338	47,179	20,136	11,353	8,605	6,568	4,186	2,844	1,695	1,616	1,367	1,134	5,835	357,856
		200902	237,859	52,993	17,142	10,169	6,947	5,589	4,925	3,133	2,118	1,414	1,267	1,094	5,767	350,417
		200903	215,366	53,187	21,580	9,393	5,789	4,725	4,587	3,461	2,557	1,780	1,225	1,034	5,841	330,525
		200904	232,777	43,723	21,106	11,441	6,025	4,010	3,594	3,628	2,742	2,068	1,478	1,059	5,939	339,590
		200905	248,246	47,115	17,975	10,095	7,034	3,745	2,972	2,867	2,732	2,358	1,616	1,299	5,975	354,029

Division Data Request 5-C

Request:

C. Average Monthly Bill History

Time period:	Monthly for 2007, 2008 & YTDMay 2009
Type of accounts:	Rhode Island-based accounts
Data Type:	Average monthly bill for the following types of customers: residential (2) non-residential
File Format:	MS Excel worksheet
File Key:	N/A
Data Delivery:	TBD – secure FTP website, Compact Disk or email

Response:

Please see Attachment DIV-5-C for the requested information.

Prepared by or under the supervision of: Rudy L. Wynter

NARRAGANSETT ELECTRIC
AVERAGE BILLS
2007, 2008 & YTD May 2009

Revenue Year	Res / Comm Indicator		Revenue Month 1	2	3	4	5	6	7	8	9	10	11	12
2007	C		$ 791.90	$ 698.97	$ 724.56	$ 667.21	$ 676.28	$ 726.61	$ 752.59	$ 803.14	$ 794.44	$ 755.05	$ 700.63	$ 706.33
2007	R		$ 94.69	$ 84.27	$ 82.48	$ 72.71	$ 65.61	$ 73.20	$ 87.60	$ 103.19	$ 93.05	$ 74.90	$ 71.51	$ 89.81
2008	C	**(1)**	na	$ 605.70	$ 543.44	$ 655.33	$ 520.15	$ 571.19	$ 643.71	$ 811.63	$ 919.07	$ 826.26	$ 463.42	$ 659.68
2008	R	**(1)**	na	$ 86.90	$ 83.32	$ 77.06	$ 66.25	$ 76.88	$ 107.17	$ 138.32	$ 111.97	$ 89.24	$ 91.18	$ 106.94
2009	C		$ 733.41	$ 590.68	$ 553.68	$ 489.11	$ 506.90							
2009	R		$ 120.47	$ 87.24	$ 83.92	$ 79.92	$ 70.28							

(1) January 2008 was the CSS conversion month. The data is inconsistent for that month.

Division Data Request 6-13

Request:

Re: page 42 of 97, Figure NG-SFT-6 of witness Tierney's testimony, please provide:

a. The source data, documents, and assumptions used in the development of the data points graphed;

b. The monthly billings for Distribution Service that were actually paid by Residential Customers for the years 2003 though 2008 in the absence of the proposed RDM;

c. Corresponding graphs and data each **non-residential** rate class, as well as the source data, calculations, and assumptions used to compute the data points graphed for each rate class.

d. The monthly billings for Distribution Service that were actually paid by customers in each Non-Residential rate class for the years 2003 though 2008 in the absence of the proposed RDM;

e. The Company's achieved rate of return on equity in each year 2003 through 2008 with and without the RDM in-place.

Response:

a. Attachment DIV 6-13 provides background information used in the development of Figure NG-SFT-6 of Dr. Tierney's prefiled expert testimony.

b. Attachment DIV 6-13 provides annual data on customer billings used in the development of Figure NG-SFT-6 of Dr. Tierney's prefiled expert testimony.

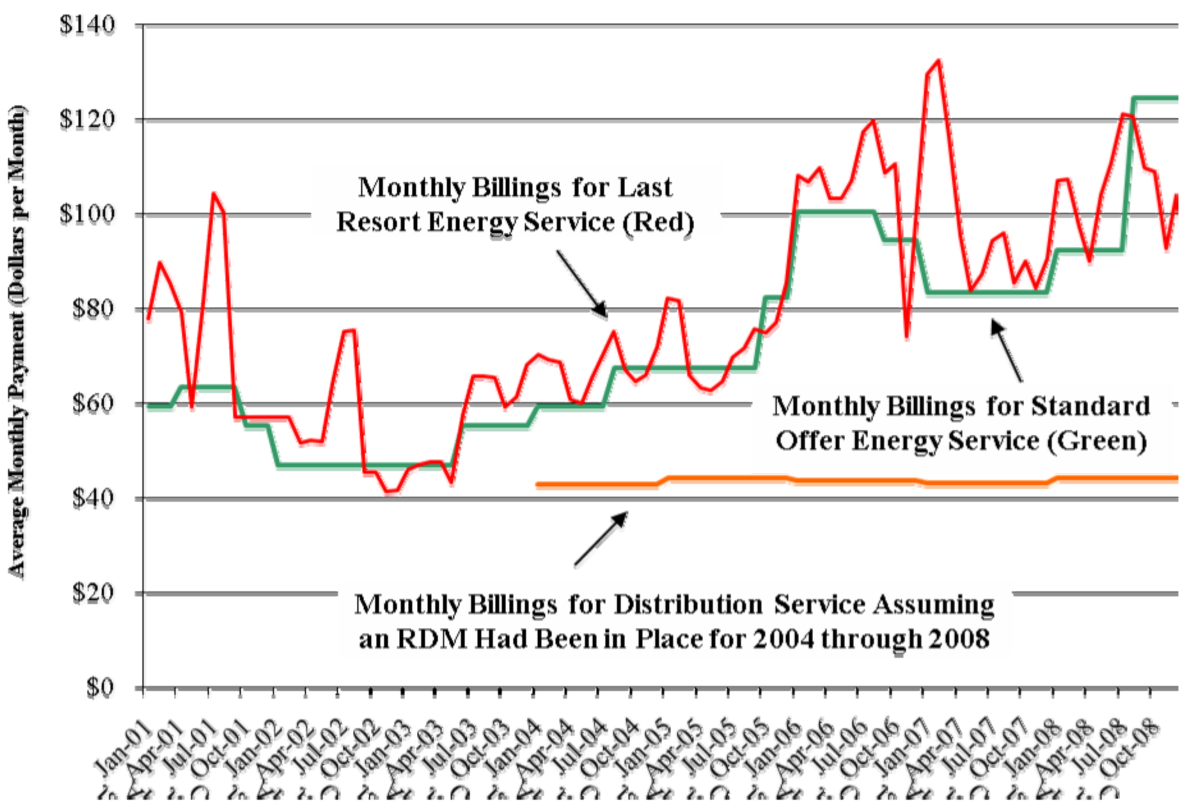
c. Figure NG-SFT-6 of Dr. Tierney's prefiled expert testimony compares monthly residential customers billing for Standard Offer Service with the billings for distribution service had the Company had revenue decoupling over the period 2003 to 2008. Figure Div 6-13-1 and Figure 6-13-2, below, provide similar comparisons for different customer classes as those depicted in Figure NG-SFT-6. Figure Div 6-13-1 compares monthly billings for commercial customers under two types of energy commodity service (Standard Offer and Last Resort) with billings under the Small Commercial & Industrial distribution service rate (C-06) assuming the Company had revenue decoupling. Figure DIV 6-13-2 makes this same comparison for customers under the General Commercial & Industrial service rate (G-02). The comparisons provided in these figures are illustrative

Division Data Request 6-13 (cont.)

in several respects. First, to highlight the changes in commodity and distribution service charges, monthly billings are calculated under the assumption that customer energy use is constant in all months. Second, estimates of distribution service billings reflect revenue requirements that are calculated using a simplified revenue decoupling mechanism.

d. Attachment DIV 6-13 provides annual data on customer billings used in the development of Figures DIV 6-13-1 and 6-13-2.

Figure DIV 6-13-1
National Grid Retail Unbundled Electric Service for Commercial Customer (C-06) in Rhode Island: Comparison of Monthly Distribution and Standard Offer Service Billings

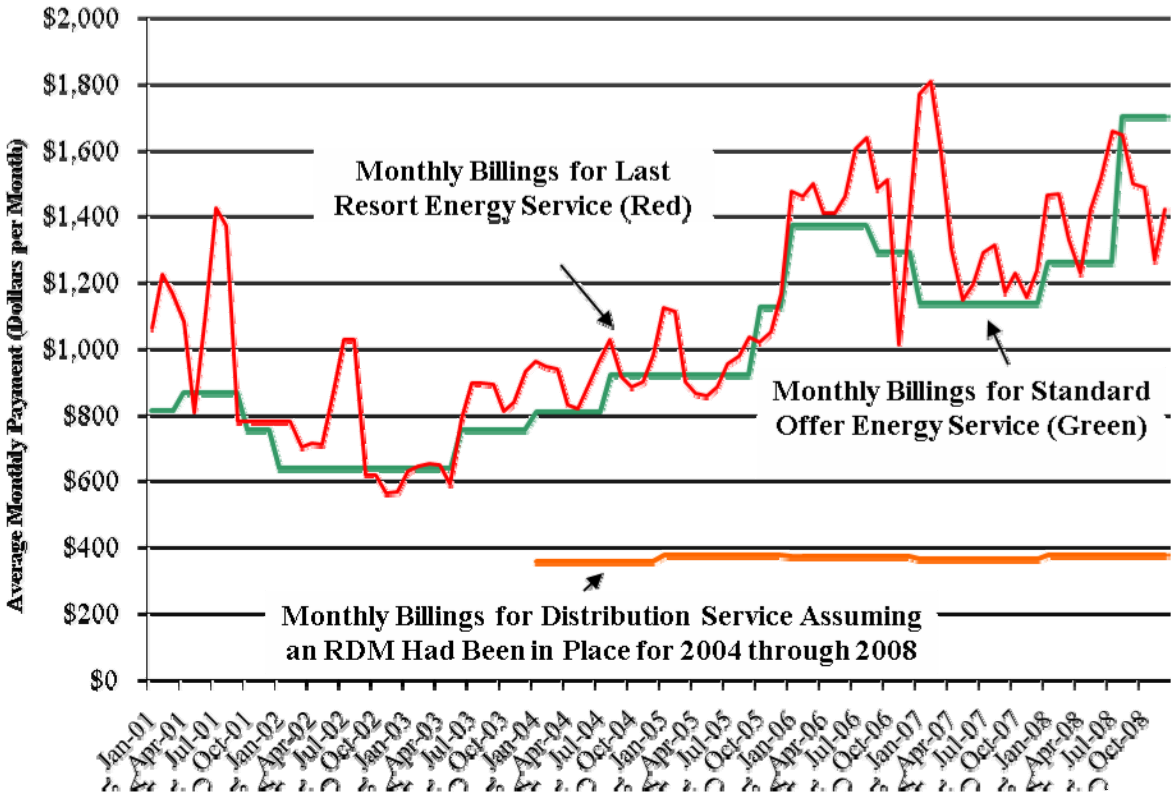


Source: National Grid, based on rate elements for a small commercial or industrial customer on C-06 distribution service.
Notes: Tierney calculation assumes that the residential customer used an amount in each year equivalent to its usage in 2008 (with no seasonal variation). The calculation of monthly billings for distribution charge is based on an assumption of a revenue decoupling mechanism having been in place during the historical period shown above.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-13 (cont.)

Figure DIV 6-13-2
National Grid Retail Unbundled Electric Service for
Commercial Customer (G-02) in Rhode Island:
Comparison of Monthly Distribution and Standard Offer Service Billings



Source: National Grid, based on rate elements for a commercial or industrial customer on G-02 distribution service.
Notes: Tierney calculation assumes that the residential customer used an amount in each year equivalent to its usage in 2008 (with no seasonal variation). The calculation of monthly billings for distribution charge is based on an assumption of a revenue decoupling mechanism having been in place during the historical period shown above.

e. This answer will be supplemented when the response to part (e) becomes available.

Prepared by or under the supervision of: Susan F. Tierney

Revenue Decoupling Simulations for National Grid Distribution Service

	2003	2004	2005	2006	2007	2008
Decoupling - Fixed Revenue						
Sales (kWh)	7,694,091,648	7,822,279,925	7,985,335,205	7,732,329,004	7,879,655,164	7,733,619,602
Average Rate (cent per kWh)	2.69	2.82	2.78	2.72	2.81	2.76
Revenue Target ($)	217,288,382	227,749,151	224,128,994	219,777,537	226,800,145	222,579,722
Billed Revenues ($)	206,827,613	220,908,540	221,639,839	210,265,774	221,508,805	213,083,453
Under / (Over) Collection	10,460,769	6,840,611	2,489,155	9,511,763	5,291,340	9,496,270
Adjustment (cents per kWh)	0.14	0.09	0.03	0.12	0.07	0.12
Rates (cents per kWh)						
A16	4.00	4.13	4.09	4.03	4.12	4.07
C06	4.26	4.40	4.35	4.29	4.39	4.33
G02	2.61	2.74	2.70	2.64	2.73	2.67
Average Customer Bill (dollars per year) based on 2008 kWh per customer						
A16	286.84	296.59	293.11	289.07	295.66	291.65
C06	513.93	530.32	524.48	517.69	528.76	522.03
G02	4,293.75	4,517.61	4,437.74	4,345.07	4,496.29	4,404.32

Sources and Notes:

Annual sales based on National Grid total sales across all customer classes.

The revenue target in 2003 equals National Grid's 2002 total distribution service revenues of $217,288,382.

The revenue target in subsequent years equals the 2003 revenue target plus the prior years over- or under-collection.

Narragansett Electric Company
Information for Calendar Years 2000-2008

	2003	2004	2005	2006	2007	2008
Retail Distribution Revenue ($)						
A16	109,945,506	109,068,088	110,506,349	105,467,657	108,627,740	108,341,731
A60	4,342,375	4,769,984	4,764,891	2,981,283	2,819,872	2,345,946
B32	-	7,043	7,875	60,688	93,070	147,273
B62	1,242,726	1,325,458	1,104,985	1,057,550	1,080,569	1,167,864
C06	23,034,951	23,368,382	24,038,039	23,217,121	23,759,819	23,674,332
G02	37,397,277	37,225,174	34,073,984	33,812,541	33,865,742	33,464,282
G32	32,947,870	33,267,269	33,546,603	32,797,362	32,603,650	32,611,611
G62	5,483,583	4,349,642	4,054,934	3,648,712	3,974,963	3,848,131
M1	129,500	125,719	122,622	122,622	122,622	115,810
X01	221,638	222,339	185,544	188,706	198,029	199,908
Streetlights	9,096,765	9,135,823	8,786,492	8,835,569	8,703,992	7,919,171
Total	$223,842,193	$222,864,921	$221,192,320	$212,189,810	$215,850,068	$213,836,059

Division Data Request 6-15

Request:

Re: page 59 of 97, lines 13-19, of witness Tierney's testimony, please:

a. Identify those expenditures that National Grid believes are "out of the control of the utility;"

b. Describe how the listed rate making tools accommodate customers' interests and concerns, in addition to accommodating "investment requirements and a fair return to investors."

c. Identify each utility (not utility holding company) that has encountered a significant decline in credit worthiness since the start of the current economic recession that was not brought about, or heavily contributed to, by credit problems or collateral requirements faced by its unregulated affiliates.

Response:

a. This answer will be supplemented when it becomes available.

b. As indicated in the referenced text of Dr. Tierney's pre-filed Direct Testimony,[1] there are many different ratemaking tools that can support utilities in undertaking needed investment to replace, refurbish, and maintain the distribution infrastructure, while providing a fair return to investors. Although not mentioned in her testimony, these ratemaking mechanisms can provide many important benefits to customers, and would not be proposed by National Grid if they did not ultimately benefit customers by "accommodating investment requirements" and a fair return to investors.

First, as addressed in Dr. Tierney's testimony, the use of these mechanisms generally supports a utility's ability to utilize revenue decoupling as an element of ratemaking, which in turn can help to reduce disincentives for the implementation of programs designed to help customers better manage and reduce their energy use, and lower overall cost to provide electricity service to all customers. While revenue decoupling has beneficial attributes associated with better aligning the utility's financial interests with

[1] " Examples of ratemaking tools that can provide needed relief to accommodate both investment requirements and a fair return to investors include: inflation adjustments; adjustment mechanisms to enable recovery on a more real-time basis for expenditures that vary significantly from test-year levels and that are out of the control of the utility; recovery of financing costs and other costs associated with construction work in progress; other rate adjustment mechanisms for certain capital expenditures and other costs; and base rates established using future test years or hybrid test years."

Division Data Request 6-15 (cont.)

those of its customers,[2] revenue decoupling itself can eliminate the opportunity for growth in the utility's revenues, which is an important source of new capital for making infrastructure investments needed to provide service to customers. As explained more fully in Tierney's testimony, adoption of revenue decoupling may reduce sources of revenue to fund working capital as well as capital investment that the utility has tended to use as a way to help fund its operations and new investment. Fulfilling these capital needs becomes particularly important at present given the Company's growing investment needs, as a result of aging infrastructure, and growing investment cost, due to significant inflation in the cost of equipment and construction materials. Therefore, other ratemaking mechanisms can be useful to support customers' interests in maintaining and improving service quality and reliability in the presence of full revenue decoupling, because these other mechanisms help to ensure that the distribution company is able to attract sufficient capital at attractive rates to consumers so that the utility may undertake investments needed to replace, refurbish and maintain the company's distribution infrastructure. These mechanisms can also lower rates by supporting the distribution company's ability to attract the capital necessary to make productivity enhancing investments, such as investments in advanced information technologies. Finally, these ratemaking mechanisms can support rate stability for customers by smoothing increases in rates by gradually adjusting rates to reflect changes in costs as they are incurred over time. Absent such mechanisms, rate increases occur in one large incremental jump that reflects multiple years of costs increases when the Company files for their next rate increase.

c. Many investor-owned utilities have undergone credit downgrades since the current economic downturn. For example, according to the Edison Electric Institute, credit agencies downgraded nine utilities in the first quarter of 2009, while only upgrading one utility.[3] Downgrades since the economic downturn have reflected a variety of factors. While business risk at certain unregulated affiliates has affected the credit rating of a few investor-owned holding companies, the majority of downgrades have reflected other risk factors, including: increased regulatory risk, particularly in light of the outcomes of recent rate cases; growing capital spending needs or plans, particularly when not matched with corresponding increases in rates; and the adverse impacts of weakened regional

[2] It helps to align utility and customer interests in increased energy efficiency and lower overall costs to provide electricity service. Such an alignment offers significant potential to lower the total cost of customer bills, particularly given that the potentially significant savings available to consumers by reducing the energy portion of customer's bills, which is disproportionately greater than charges associated with distribution service.

[3] Edison Electric Institute, Q1 2009 Financial Update, Credit Ratings.

Division Data Request 6-15 (cont.)

economies on revenues.[4] Two examples can help to illustrate these factors. In one case, Fitch downgraded NiSource and its Northern Indiana Public Service subsidiary citing, among other factors, "weakening industrial demand, limited capital market and bank liquidity and depressed equity prices as factors that would likely lead to higher financing costs."[5] In another case, Great Plains Energy and subsidiary Kansas City Power & Light were downgraded for, among other factors, "regional economic weakness and regulatory, financial and operational challenges resulting from the company's construction."[6]

[4] Edison Electric Institute, Q4 2008 Financial Update, Credit Ratings; Edison Electric Institute, Q1 2009 Financial Update, Credit Ratings.

[5] Edison Electric Institute, Q1 2009 Financial Update, Credit Ratings, p. 4.

[6] Edison Electric Institute, Q1 2009 Financial Update, Credit Ratings, p. 4.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-19

Request:

Re: page 66 of 97, Figure NG-SFT-11, of the testimony of witness Tierney. Please provide:

a. The actual cents per kWh data used to graph each line in Figure NG-SFT-11, as well as documentation of all adjustments that National Grid or the witness made to the data reported by DOE to derive each data point that is included in the graph lines;

b. The explanation offered by DOE to explain the recent increases in the forecasted Distribution Portion of End-Use Electricity Price that can be observed in NG-SFT-11; or if no such explanation is offered by DOE, provide the Company's understanding of the major factors contributing to the increases in the Distribution Portion of End-Use Electricity Price that DOE has included in its Annual Energy Outlook publications over the past six years.

c. Any assessment offered by DOE, or made by the Company, of regional variations in the Distribution Portion of End-Use Electricity Price for the periods forecasted;

d. Any assessment made by the Company of the correspondence between National Grid's actual end-use distribution prices for the years 2006, 2007, and 2008 and the DOE forecasts for those years, and the supporting workpapers, data, and assumptions relied upon in making that assessment;

e. The Company's assessment of its actual end-use distribution prices for the years 2006, 2007, and 2008 by rate class and the supporting workpapers, data, and assumptions relied upon in making that assessment; and

f. The Company's best estimates (along with all supporting workpapers and assumptions) of the actual end-use distribution prices in average cents per kWh that its customers will experience in each of the next three years assuming:

   i. All of its proposals in this proceeding, **including** its RDR Plan, are adopted as presented and its energy efficiency goals are achieved;

   ii. All of its proposals in this proceeding, **excluding** its RDR Plan, are adopted as presented and its energy efficiency goals are achieved.

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Division Data Request 6-19 (cont.)

Response:

a. The electricity price data shown in Figure NG-SFT-11 reflect the average U.S. prices associated with the distribution service category. These data are published as part of the Annual Energy Outlook ("AEO") published by the Energy Information Administration ("EIA") each year. The AEO forecasts the distribution, generation, and transmission portion of average electricity prices separately.

   The cents-per-kWh data shown in Figure NG-SFT-11 are the AEO forecasts that have been adjusted to constant 2000 dollars using actual CPI to deflate other years' values.

   Attachment DIV 6-19 provides the following information:

   - AEO forecast data used in Figure NG-SFT-11;
   - Original AEO data for each forecast year; and
   - CPI data.

b. The EIA provides no specific explanation for the rise in forecasted distribution service costs over the past decade.[1] The EIA does identify rising capital costs as one factor, among many, affecting the increase in real electricity prices (reflecting combined generation, transmission, and distribution) in recent years.[2]

c. We are unaware of any assessments of regional variation in distribution costs performed by EIA.

d. As discussed in some detail in other parts of Dr. Tierney's pre-filed direct testimony (e.g., pages 62-70), several trends have been working in tandem to increase the capital requirements for distribution utilities. A key factor in increasing capital requirements in recent years has been increases in the cost of distribution plant. Figure NG-SFT-12 through NG-SFT-14 shows the rising price indices for materials used in distribution investments, including: electric wire and cable, cement and crushed stone, and steel mill product.

   As shown in Figure NG-SFT-10 of her pre-filed direct testimony (reproduced below), costs for the construction of distribution plant have been increasing significantly over

[1] See the following webpage for an explanation of the assumptions used in the electricity portion of the AEO. http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html
[2] http://www.eia.doe.gov/oiaf/aeo/electricity.html

Division Data Request 6-19 (cont.)

levels in prior years, especially in the Northeast. For example, the Handy-Whitman index reflecting the cost of distribution plant has risen by 78 percent since January 2000, and by 44 percent since January 2005. In parallel with these increases in the input costs of distribution plant, the amount of investment needed to maintain, replace, refurbish, and in some cases expand the distribution infrastructure has been growing. This reflects the fact that infrastructure for many distribution utilities, including the Company, is relatively old, continues to age, and requires attention to assure reliable service at reasonable cost. Figure DIV 6-19 below shows investment in distribution plant by investor-owned utilities in both real and nominal terms from 1990 through 2006. Growth in investment (in nominal dollars) over this period reflects both the increase in the price of distribution plant – as reflected by the Handy-Whitman index in Figure NG-SFT-10 – and increases in the quantity of distribution plant investment. However, changes in plant investment expressed in real dollars (which is calculated by deflating nominal investment by the Handy-Whitman index) reflect only changes in the quantity of distribution plant investment. Thus, the increases in plant investment (in real dollars) in recent years illustrates that distribution utilities have required increasing amounts of investment in distribution infrastructure in recent years. The increases in recent years have been most significant, with real investment increasing by 17 percent since 2003.

Attachment DIV 6-19 provides the following information used in developing Figure DIV 6-19:

- EIA Distribution Construction Expenditures

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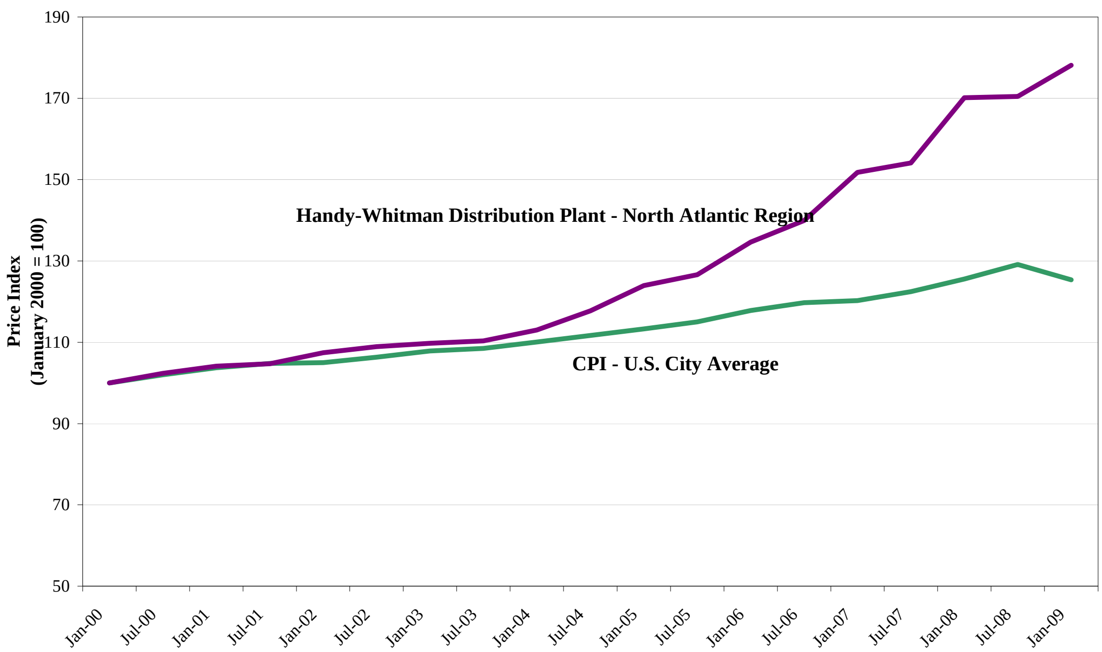
Division Data Request 6-19 (cont.)

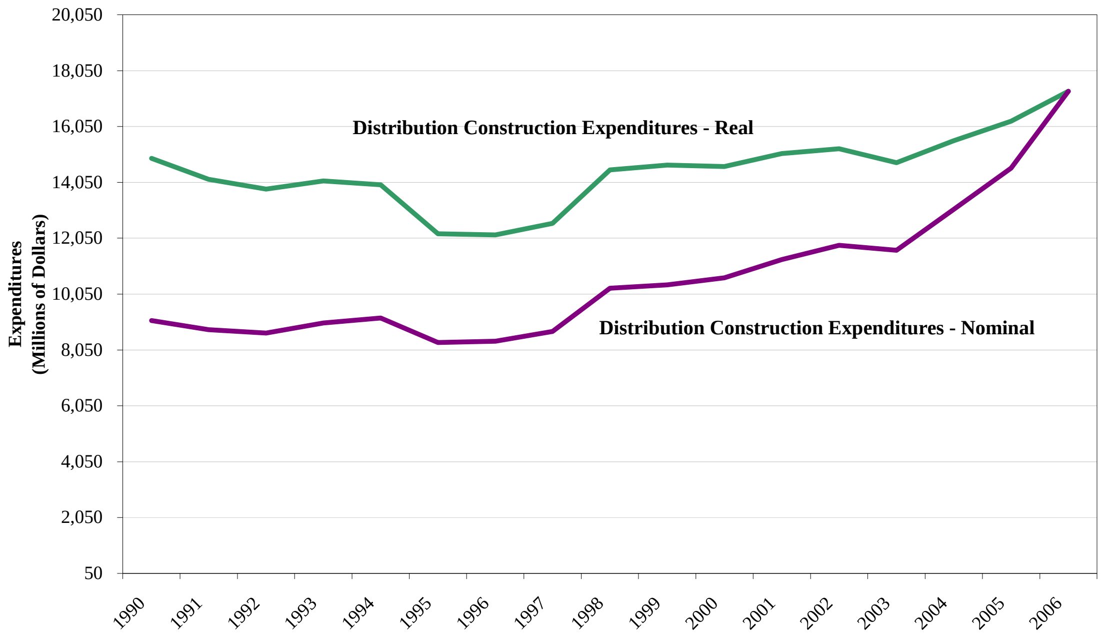
Figure NG-SFT-10
Comparison of Consumer Price Index to
Electric Distribution Construction Cost Index (North America)



Sources:
Bureau of Labor Statistics, accessed April 30, 2009.
1 The Handy-Whitman Index of Public utility Construction Costs, Cost Trends of Electric Utility Construction, updated January 2009.

Division Data Request 6-19 (cont.)

Figure DIV 6-19
Distribution Construction Expenditures for Investor Owned Utilities, 1990-2006



Source:
Edison Electric Institute, Table 9.1: Construction Expenditures for Transmission and Distribution:
<http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Documents/Transmission-Investment-Expenditures.pdf>.

(e) This answer will be supplemented when the response to part (e) becomes available.

(f) (i) Illustrative rates for 2010, 2011, and 2012, assuming that the Commission approves all of the Company's rate proposals in this docket and energy efficiency goals are achieved, are included in Attachment DIV-6-19(f)-1. Page 1 of the attachment is a summary of the illustrative average distribution rates for each rate class for each of the three years. Page 2 is based on Schedule NG-RLO-7, which is an illustration of the calculation of the revenue decoupling mechanism and includes the Company's illustration of the net inflation and projected capital expenditure for 2010 through 2012. Pages 3 and 4 calculate the revenue decoupling adjustments, based on the inflation and capital expenditure assumptions from page 2, for 2011 and 2012. Page 5 calculates an illustrative pension adjustment, based on the projected pension expense for 2011 and 2012 from Schedule NG-RLO-5. The Company does not have a projection of the estimated inspection and maintenance expense for 2011 and 2012 at this time,

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Division Data Request 6-19 (cont.)

therefore, inspection and maintenance O&M expense is held constant for illustrative purposes only for 2011 and 2012.

. All calculations and assumptions are intended to illustrate changes in the Company's rates and are not intended to estimate what those rates will be for the years indicated.

(f)(ii.) Attachment DIV-6-19(f)-2 is a summary of illustrative rates for 2010, 2011, and 2012, assuming that the Commission approves all of the Company's rate proposals in this docket except the revenue decoupling proposal, and energy efficiency goals are achieved. As with the Company's response to subpart i., these rates are intended to illustrate changes that may occur under certain assumptions.

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Figure NG-SFT-11 Source data

	Dollar Unit	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
AEO 2009	2007 cents	2.412687063	2.387317181	2.328172684	2.34778738	2.356847525	2.419854641	2.429812193	2.427305222	2.429819822
AEO 2008	2006 cents	2.321531534	2.299117327	2.247082472	2.30531168	2.299029589	2.290632725	2.284408092	2.293762445	2.297322273
AEO 2007	2005 cents	2.108444929	2.101720095	2.068991661	2.076886415	2.073610306	2.070177555	2.063812494	2.058378696	2.054657936
AEO 2006	2004 cents	2.052022696	2.043300867	2.007356882	2.005416155	2.003673315	1.988938689	1.970040917	1.956362367	1.944134355
AEO 2005	2003 cents	2.045497656	2.01194644	1.991580963	1.984157562	1.972234607	1.952905655	1.934183002	1.920773745	1.908625603
AEO 2004	2002 cents	1.967076182	1.945302367	1.937845588	1.936334968	1.931235909	1.9015311	1.878473878	1.858983994	1.843380928

Adjusted to Real 2000 Dolllars		**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
AEO 2009	2000 cents	2.003765336	1.982695346	1.933575137	1.949865376	1.957389934	2.009718095	2.01798796	2.015905891	2.017994296
AEO 2008	2000 cents	1.982974852	1.963829383	1.919382945	1.969120393	1.96375444	1.956582119	1.951265246	1.959255422	1.962296108
AEO 2007	2000 cents	1.85905897	1.853129546	1.824272217	1.831233184	1.828344571	1.825317844	1.81970564	1.81491455	1.811633879
AEO 2006	2000 cents	1.870610419	1.862659658	1.829893357	1.828124203	1.826535441	1.813103453	1.795876368	1.783407091	1.772260116
AEO 2005	2000 cents	1.914319002	1.88291944	1.86386001	1.856912675	1.845754344	1.827664966	1.810143005	1.797593689	1.786224613
AEO 2004	2000 cents	1.88288226	1.862040398	1.85490278	1.853456817	1.848576007	1.82014261	1.798072272	1.779416585	1.764481355

CPI Deflator	
2000	1
2001	0.972332016
2002	0.957198444
2003	0.935869565
2004	0.911593436
2005	0.88172043
2006	0.854166667
2007	0.830511908
2008	0.799803068

Figure NG-SFT-11 Source data

	Dollar Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEO 2009	2007 cents	2.428030252	2.416208982	2.409021616	2.39983654	2.392486572	2.38957262	2.38843894	2.391912699	2.359945059
AEO 2008	2006 cents	2.291475534	2.284535408	2.284967899	2.280963898	2.279790878	2.278407574	2.272983074	2.270663023	2.23566699
AEO 2007	2005 cents	2.05087018	2.042621374	2.039190054	2.038143873	2.034194469	2.028389454	2.022354364	2.016167402	1.978073716
AEO 2006	2004 cents	1.930591464	1.918765068	1.906403422	1.892545104	1.881407738	1.871853113	1.861980438	1.852610826	1.828475237
AEO 2005	2003 cents	1.895036697	1.886481643	1.874884963	1.861028671	1.846632838	1.832758307	1.824044466	1.812626123	1.786257029
AEO 2004	2002 cents	1.821679354	1.804344177	1.78734386	1.781141162	1.765096664	1.753471375	1.743638873	1.734295249	1.7237854

Adjusted to Real 2000 Dolllars		2015	2016	2017	2018	2019	2020	2021	2022	2023
AEO 2009	2000 cents	2.016508037	2.006690332	2.000721138	1.993092824	1.986988588	1.984568516	1.983626981	1.986511979	1.959962473
AEO 2008	2000 cents	1.957302019	1.951373994	1.951743414	1.948323329	1.947321375	1.946139803	1.941506376	1.939524665	1.909632221
AEO 2007	2000 cents	1.808294137	1.801020997	1.797995531	1.797073093	1.793590823	1.788472422	1.78315116	1.777695989	1.744108008
AEO 2006	2000 cents	1.759914506	1.749133641	1.737864846	1.725231694	1.715078944	1.706369011	1.697369145	1.688827868	1.666826023
AEO 2005	2000 cents	1.77350717	1.765500755	1.754647775	1.741680093	1.728207471	1.71522272	1.707067701	1.696381622	1.671703589
AEO 2004	2000 cents	1.743708642	1.727115438	1.710842761	1.704905548	1.68954778	1.678420071	1.669008415	1.660064713	1.650004702

CPI Deflator	
2000	1
2001	0.972332016
2002	0.957198444
2003	0.935869565
2004	0.911593436
2005	0.88172043
2006	0.854166667
2007	0.830511908
2008	0.799803068

Figure NG-SFT-11 Source data

	Dollar Unit	2024	2025	2026	2027	2028	2029	2030
AEO 2009	2007 cents	2.362769127	2.367574453	2.367228031	2.359883785	2.351261854	2.339957476	2.323764563
AEO 2008	2006 cents	2.228298903	2.22333312	2.218137264	2.21170187	2.207448959	2.202422619	2.197724819
AEO 2007	2005 cents	1.970315933	1.963586807	1.955417871	1.948071837	1.940743804	1.933419228	1.927038074
AEO 2006	2004 cents	1.820942163	1.81386888	1.806572318	1.800951838	1.794123292	1.788693309	1.785742998
AEO 2005	2003 cents	1.772847414	1.761561394					
AEO 2004	2002 cents	1.720402122	1.716662765					

Adjusted to Real 2000 Dolllars		2024	2025	2026	2027	2028	2029	2030
AEO 2009	2000 cents	1.962307895	1.966298776	1.966011069	1.959911585	1.952750968	1.943362547	1.92991414
AEO 2008	2000 cents	1.903338646	1.89909704	1.894658913	1.889162014	1.885529319	1.881235987	1.877223283
AEO 2007	2000 cents	1.737267812	1.731334604	1.724131887	1.717654738	1.711193462	1.704735233	1.699108839
AEO 2006	2000 cents	1.659958923	1.653510964	1.646859466	1.641735874	1.635511016	1.630561079	1.627871595
AEO 2005	2000 cents	1.659153939	1.648591696					
AEO 2004	2000 cents	1.646766233	1.643186926					

CPI Deflator	
2000	1
2001	0.972332016
2002	0.957198444
2003	0.935869565
2004	0.911593436
2005	0.88172043
2006	0.854166667
2007	0.830511908
2008	0.799803068

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Table 8. Electricity Supply, Disposition, Prices, and Emissions
(billion kilowatthours, unless otherwise noted)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2007-2030
Net Generation by Fuel Type																										
Electric Power Sector 1/																										
Power Only 2/																										
Coal	1934	1965	1968	1949	2006	2034	2050	2057	2059	2065	2070	2080	2085	2092	2093	2087	2094	2093	2100	2120	2147	2181	2223	2280	2334	0.8%
Petroleum	55	57	42	42	43	43	43	43	44	44	44	44	44	44	44	44	44	45	45	45	45	45	45	46	46	-0.9%
Natural Gas 3/	618	685	686	664	629	618	636	619	614	617	640	655	673	681	687	710	739	781	814	824	827	825	805	785	772	0.5%
Nuclear Power	787	806	799	807	809	812	815	818	827	831	832	835	837	848	862	866	867	867	867	867	871	878	892	908	907	0.5%
Pumped Storage/Other 4/	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	8.8%
Renewable Sources 5/	348	314	356	379	411	424	435	446	462	473	490	503	519	530	543	552	558	567	574	581	590	594	605	606	610	2.9%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	- -
Total	3742	3827	3852	3841	3899	3932	3980	3984	4006	4030	4076	4118	4159	4195	4230	4261	4303	4354	4401	4438	4481	4524	4571	4626	4670	0.9%
Combined Heat and Power 6/																										
Coal	36	37	32	31	32	32	32	31	31	32	31	31	31	31	32	32	32	32	32	32	32	32	32	32	32	-0.6%
Petroleum	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-10.0%
Natural Gas	116	129	120	117	107	104	109	111	106	112	110	114	115	116	114	113	115	115	113	114	111	111	111	109	109	-0.7%
Renewable Sources	4	4	4	4	4	4	4	5	5	4	5	5	5	6	5	5	5	5	5	5	5	5	5	5	5	0.6%
Total	165	179	156	153	143	141	145	147	143	148	147	151	153	153	151	151	152	152	151	151	148	149	148	147	146	-0.9%
Total Net Generation	3908	4006	4008	3994	4042	4073	4126	4131	4149	4178	4223	4269	4311	4348	4381	4411	4455	4507	4551	4589	4629	4672	4719	4773	4816	0.8%
Less Direct Use	33	34	34	34	34	34	34	33	33	33	33	34	34	34	34	34	34	34	34	34	34	34	34	33	33	-0.1%
Net Available to the Grid	3875	3972	3975	3960	4009	4039	4092	4098	4115	4145	4189	4235	4278	4315	4348	4378	4422	4473	4518	4556	4595	4639	4686	4739	4783	0.8%
End-Use Generation 7/																										
Coal	22	19	19	19	19	19	20	21	24	25	26	27	28	29	31	32	34	35	37	39	41	43	44	46	48	4.1%
Petroleum	4	4	5	5	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	14	13	13	14	14	5.6%
Natural Gas	77	78	81	83	78	80	82	83	85	87	89	91	93	95	97	100	103	106	108	112	115	119	123	127	131	2.3%
Other Gaseous Fuels 8/	5	5	5	5	16	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	5.1%
Renewable Sources 9/	34	33	34	35	36	38	40	43	45	50	56	58	60	64	69	75	84	88	93	98	102	106	109	113	116	5.6%
Other 10/	13	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	-0.4%
Total	155	153	156	159	174	178	183	188	195	203	211	216	222	229	237	248	261	270	280	289	299	308	317	327	337	3.5%
Less Direct Use	124	122	125	127	142	144	148	153	158	164	172	175	179	183	188	194	201	208	215	223	230	237	245	253	261	3.4%
Total Sales to the Grid	31	31	31	32	33	34	35	36	37	38	39	41	43	45	49	54	60	62	64	66	69	71	73	74	76	3.9%
Total Electricity Generation by Fuel																										
Coal	1992	2021	2019	1999	2057	2085	2102	2110	2114	2121	2127	2138	2144	2153	2156	2151	2160	2161	2169	2191	2219	2255	2299	2358	2415	0.8%
Petroleum	64	66	47	47	56	57	57	57	57	57	58	58	58	58	58	58	58	58	59	59	59	59	59	60	60	-0.3%
Natural Gas	812	892	887	864	814	802	827	814	806	815	839	860	881	891	898	924	957	1002	1036	1050	1053	1054	1038	1021	1012	0.6%
Nuclear Power	787	806	799	807	809	812	815	818	827	831	832	835	837	848	862	866	867	867	867	867	871	878	892	908	907	0.5%
Renewable Sources 5,9/	386	352	394	418	451	466	480	493	512	527	551	566	585	599	617	633	647	661	673	684	697	705	719	724	730	3.2%
Other 11/	23	22	18	18	29	29	28	28	28	28	27	27	28	28	28	28	28	28	28	28	28	28	28	28	28	1.1%
Total	4063	4159	4164	4153	4217	4250	4309	4320	4344	4381	4434	4485	4533	4577	4618	4659	4716	4776	4831	4879	4928	4980	5037	5100	5153	0.9%
Total Electricity Generation	4063	4159	4164	4153	4217	4250	4309	4320	4344	4381	4434	4485	4533	4577	4618	4659	4716	4776	4831	4879	4928	4980	5037	5100	5153	0.9%
Total Net Generation to the Grid	3906	4004	4006	3992	4042	4073	4127	4134	4153	4183	4229	4276	4320	4360	4396	4431	4482	4535	4582	4622	4664	4709	4758	4814	4859	0.8%
Net Imports	18	31	36	26	24	26	22	23	24	17	17	16	20	22	18	20	15	10	14	14	20	24	29	21	28	-0.5%
Electricity Sales by Sector																										
Residential	1352	1392	1389	1384	1406	1412	1421	1409	1415	1423	1435	1448	1466	1485	1499	1511	1528	1546	1567	1581	1599	1617	1638	1651	1667	0.8%
Commercial	1300	1343	1354	1350	1393	1414	1433	1454	1479	1505	1533	1559	1584	1609	1632	1657	1680	1703	1724	1743	1763	1784	1805	1828	1850	1.4%
Industrial	1011	1006	1014	986	979	992	1020	1029	1026	1025	1027	1031	1032	1029	1021	1020	1022	1026	1032	1036	1042	1050	1058	1067	1077	0.3%
Transportation	6	6	7	7	7	7	7	7	8	8	8	9	9	9	10	10	11	11	12	12	13	13	14	14	15	3.7%
Total	3669	3747	3763	3726	3785	3824	3881	3899	3928	3960	4003	4047	4092	4132	4162	4197	4241	4286	4335	4373	4417	4464	4515	4560	4609	0.9%
Direct Use	157	156	158	161	175	178	182	186	191	198	205	209	213	217	222	228	234	241	249	257	264	271	278	286	294	2.8%
Total Electricity Use	3826	3903	3922	3886	3960	4002	4063	4085	4119	4158	4208	4255	4305	4349	4384	4425	4475	4528	4584	4629	4681	4735	4793	4846	4903	1.0%
End-Use Prices																										
(2007 cents per kilowatthour)																										
Residential	10.6	10.6	11.0	11.1	10.5	10.7	10.7	10.8	10.8	10.8	10.9	10.9	11.0	11.1	11.2	11.1	11.2	11.3	11.4	11.6	11.8	11.9	12.0	12.1	12.2	0.6%
Commercial	9.7	9.6	10.1	10.1	9.3	9.4	9.3	9.3	9.2	9.3	9.3	9.3	9.4	9.5	9.6	9.6	9.6	9.6	9.8	10.0	10.1	10.3	10.4	10.5	10.6	0.4%
Industrial	6.3	6.4	7.1	7.0	6.4	6.4	6.3	6.3	6.2	6.3	6.3	6.3	6.4	6.5	6.5	6.5	6.5	6.6	6.7	6.9	7.0	7.1	7.2	7.3	7.4	0.6%
Transportation	10.4	10.5	11.7	11.5	10.4	10.4	10.4	10.4	10.3	10.3	10.2	10.0	10.0	10.1	10.1	10.0	10.1	10.3	10.5	10.8	11.0	11.2	11.4	11.5	11.7	0.5%
All Sectors Average	9.1	9.1	9.6	9.6	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.3	9.4	9.4	9.4	9.5	9.6	9.8	10.0	10.1	10.2	10.3	10.4	0.6%
(nominal cents per kilowatthour)																										
Residential	10.4	10.6	11.3	11.5	11.1	11.4	11.7	12.0	12.2	12.5	12.9	13.2	13.6	14.0	14.4	14.7	14.9	15.2	15.6	16.0	16.4	16.8	17.1	17.4	17.7	2.2%
Commercial	9.4	9.6	10.3	10.5	9.8	10.0	10.1	10.3	10.4	10.7	11.0	11.3	11.7	12.1	12.4	12.6	12.8	13.0	13.4	13.8	14.1	14.4	14.8	15.0	15.3	2.1%
Industrial	6.1	6.4	7.2	7.3	6.7	6.8	6.8	6.9	7.1	7.2	7.4	7.7	7.9	8.2	8.4	8.5	8.7	8.9	9.2	9.5	9.7	10.0	10.2	10.4	10.7	2.3%
Transportation	10.1	10.5	11.9	12.0	10.9	11.1	11.3	11.5	11.6	11.9	12.1	12.2	12.4	12.7	13.0	13.1	13.5	13.9	14.4	14.9	15.3	15.7	16.2	16.5	16.9	2.1%
All Sectors Average	8.9	9.1	9.9	10.1	9.5	9.7	9.8	10.0	10.2	10.5	10.8	11.1	11.4	11.8	12.2	12.3	12.6	12.8	13.2	13.6	13.9	14.2	14.6	14.8	15.1	2.2%
Prices by Service Category																										
(2007 cents per kilowatthour)																										
Generation	6.0	6.0	6.7	6.7	6.0	5.9	5.9	5.9	5.8	5.9	5.9	6.0	6.1	6.2	6.2	6.2	6.2	6.3	6.5	6.6	6.8	6.9	7.0	7.1	7.3	0.8%
Transmission	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.3%
Distribution	2.4	2.4	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.3	2.3	-0.1%
(nominal cents per kilowatthour)																										
Generation	5.9	6.0	6.8	6.9	6.3	6.3	6.4	6.5	6.6	6.8	7.0	7.2	7.5	7.8	8.1	8.2	8.3	8.6	8.8	9.2	9.4	9.7	10.0	10.3	10.5	2.4%
Transmission	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	3.0%
Distribution	2.3	2.4	2.4	2.4	2.5	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4	1.5%
Electric Power Sector Emissions 1/																										
Sulfur Dioxide (million tons)	9.40	8.95	8.49	8.18	7.51	6.74	6.35	6.74	6.93	4.17	3.90	3.85	3.84	3.84	3.86	3.83	3.82	3.78	3.79	3.78	3.76	3.75	3.78	3.75	3.74	-3.7%
Nitrogen Oxide (million tons)	3.41	3.29	3.49	2.34	2.37	2.34	2.31	2.32	2.32	2.10	2.09	2.09	2.09	2.10	2.10	2.09	2.09	2.10	2.10	2.10	2.10	2.11	2.11	2.11	2.12	-1.9%
Mercury (tons)	49.04	49.28	48.06	46.02	45.19	44.68	43.31	43.70	43.68	29.08	28.95	28.68	29.17	28.88	29.13	28.81	29.22	29.43	29.29	29.44	29.69	29.40	29.44	29.72	29.57	-2.2%

1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy, (Washington, DC, May 2007).
5/ Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
6/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
7/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
8/ Includes refinery gas and still gas.
9/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.
10/ Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
11/ Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), Annual Energy Review 2007, DOE/EIA-0384(2007) (Washington, DC, June 2008) and supporting databases. 2006 and 2007 prices: EIA, AEO2009 National Energy Modeling System run aeo2009.d120908a. Projections: EIA, AEO2009 National Energy Modeling System run aeo2009.d120908a.

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Table 8. Electricity Supply, Disposition, Prices, and Emissions
(billion kilowatthours, unless otherwise noted)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2006-2030
Net Generation by Fuel Type																											
Electric Power Sector 1/																											
Power Only 2/																											
Coal	1956	1930	1971	1961	1982	2002	2044	2070	2085	2109	2122	2142	2175	2220	2255	2287	2331	2368	2413	2461	2502	2544	2592	2641	2692	2756	1.5%
Petroleum	111	55	48	48	48	49	49	50	50	49	50	50	50	51	51	52	52	53	53	54	54	54	55	56	56	56	0.1%
Natural Gas 3/	554	608	683	700	695	695	692	698	666	667	682	694	685	661	638	614	594	584	568	556	543	538	533	525	508	503	-0.8%
Nuclear Power	782	787	800	800	795	797	799	802	803	806	807	809	816	829	846	868	874	883	892	900	911	920	925	926	928	917	0.6%
Pumped Storage/Other 4/	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	5.4%
Renewable Sources 5/	319	347	337	360	382	421	432	440	449	457	465	476	482	494	503	518	520	523	529	534	540	542	544	551	553	553	2.0%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	3	3	3	4	- -
Total	3722	3727	3840	3868	3904	3965	4018	4061	4055	4090	4128	4173	4210	4256	4295	4340	4373	4412	4457	4507	4552	4602	4653	4702	4740	4790	1.1%
Combined Heat and Power 6/																											
Coal	37	36	32	32	32	32	31	31	31	31	32	32	32	32	32	32	32	32	32	32	32	32	32	32	31	31	-0.6%
Petroleum	6	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-6.7%
Natural Gas	130	124	121	118	120	124	125	124	121	118	123	126	124	120	115	108	107	104	103	100	99	99	98	98	98	96	-1.1%
Renewable Sources	4	4	3	3	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0.5%
Total	180	173	157	154	156	160	161	160	157	155	160	163	161	157	152	145	144	142	140	138	136	136	135	136	134	133	-1.1%
Total Net Generation	3902	3900	3996	4022	4059	4125	4179	4221	4212	4245	4288	4336	4372	4413	4448	4485	4517	4554	4597	4645	4688	4737	4788	4838	4875	4923	1.0%
Less Direct Use	33	33	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	0.1%
Net Available to the Grid	3869	3866	3962	3988	4025	4091	4145	4188	4178	4211	4254	4302	4338	4380	4414	4451	4483	4520	4563	4611	4654	4703	4754	4804	4841	4889	1.0%
End-Use Generation 7/																											
Coal	22	22	22	22	21	21	28	29	26	26	28	30	34	38	38	39	40	40	41	41	41	43	44	47	49	49	3.5%
Petroleum	6	4	5	5	6	6	6	6	6	6	6	6	6	6	7	7	8	9	9	9	9	9	10	9	9	9	3.6%
Natural Gas	73	74	78	79	86	88	90	92	94	96	99	101	103	106	108	111	113	116	119	121	124	126	129	132	135	138	2.6%
Other Gaseous Fuels 8/	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-0.7%
Renewable Sources 5/	34	34	35	36	36	37	38	39	43	47	48	50	53	55	59	65	73	82	85	89	94	97	98	98	99	100	4.6%
Other 9/	14	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	-0.4%
Total	152	152	157	159	165	169	178	182	186	191	197	204	212	221	229	238	250	263	270	277	285	291	296	303	309	313	3.1%
Less Direct Use	123	121	125	127	132	134	141	144	147	150	155	160	165	172	177	182	188	193	200	205	211	216	220	225	230	234	2.8%
Total Sales to the Grid	30	31	31	32	34	34	37	38	39	40	42	44	46	49	52	56	62	70	71	72	74	75	76	78	79	79	4.0%
Total Electricity Generation	4054	4051	4153	4180	4225	4294	4357	4403	4398	4436	4485	4540	4583	4635	4676	4723	4767	4817	4867	4922	4973	5029	5084	5141	5184	5235	1.1%
Total Net Generation to the Grid	3899	3897	3994	4020	4059	4126	4182	4226	4217	4251	4296	4346	4384	4429	4466	4507	4546	4589	4633	4683	4728	4779	4830	4882	4920	4968	1.0%
Net Imports	25	18	26	26	22	15	14	17	19	18	11	13	15	15	17	13	14	14	15	16	16	16	16	16	21	23	1.0%
Electricity Sales by Sector																											
Residential	1359	1351	1391	1405	1428	1450	1465	1484	1456	1462	1472	1488	1499	1514	1528	1540	1549	1565	1582	1604	1620	1641	1662	1686	1702	1722	1.0%
Commercial	1275	1300	1341	1353	1369	1386	1410	1434	1462	1492	1522	1552	1579	1606	1634	1661	1691	1719	1747	1774	1802	1830	1858	1886	1913	1941	1.7%
Industrial	1019	1002	1004	1008	1003	1027	1045	1052	1054	1054	1058	1060	1061	1060	1056	1052	1051	1047	1045	1043	1041	1041	1040	1037	1034	1033	0.1%
Transportation	6	6	6	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8	8	8	8	9	9	9	1.3%
Total	3660	3659	3744	3773	3807	3869	3927	3978	3979	4016	4059	4108	4146	4188	4225	4261	4298	4339	4382	4430	4472	4520	4569	4617	4658	4705	1.1%
Direct Use	156	154	159	161	166	168	175	178	181	184	189	194	199	206	211	216	222	227	234	239	245	250	254	259	264	267	2.3%
Total Electricity Use	3815	3814	3903	3934	3972	4037	4102	4155	4159	4200	4248	4302	4346	4394	4436	4477	4520	4567	4615	4669	4717	4770	4823	4877	4922	4972	1.1%
End-Use Prices (2006 cents per kilowatthour)																											
Residential	9.7	10.4	10.4	10.5	10.8	10.7	10.5	10.4	10.3	10.3	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.5	0.0%
Commercial	8.9	9.5	9.3	9.5	9.7	9.5	9.2	9.1	8.9	8.8	8.7	8.7	8.7	8.8	8.8	8.7	8.7	8.7	8.7	8.7	8.8	8.8	8.8	8.9	8.9	8.9	-0.2%
Industrial	5.9	6.1	6.3	6.5	6.7	6.6	6.3	6.2	6.0	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.9	5.9	5.9	6.0	6.0	6.0	-0.1%
Transportation	10.5	10.1	10.1	10.6	10.9	10.6	10.3	10.3	10.0	9.9	9.9	9.9	9.9	10.0	10.0	9.9	9.8	9.8	9.8	9.8	9.9	9.9	9.9	10.0	10.0	10.1	0.0%
All Sectors Average	8.4	8.9	8.9	9.1	9.3	9.2	8.9	8.8	8.7	8.6	8.5	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.8	8.8	8.8	0.0%
Prices by Service Category (2006 cents per kilowatthour)																											
Generation	5.4	5.9	6.0	6.2	6.4	6.2	6.0	5.9	5.7	5.5	5.5	5.5	5.6	5.6	5.6	5.6	5.5	5.6	5.6	5.7	5.7	5.7	5.7	5.8	5.8	5.9	-0.1%
Transmission	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.1%
Distribution	2.3	2.3	2.3	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	-0.2%
Electric Power Sector Emissions 1/																											
Sulfur Dioxide (million tons)	10.22	9.39	9.34	8.53	7.52	6.43	5.82	5.32	5.09	4.96	4.67	4.50	4.34	3.98	3.93	3.77	3.66	3.65	3.61	3.63	3.66	3.67	3.62	3.64	3.62	3.71	-3.8%
Nitrogen Oxide (million tons)	3.64	3.41	3.53	3.48	2.36	2.33	2.35	2.34	2.35	2.36	2.11	2.11	2.10	2.11	2.10	2.11	2.12	2.12	2.12	2.13	2.14	2.14	2.15	2.15	2.15	2.16	-1.9%
Mercury (tons)	51.72	50.37	50.77	48.43	46.58	37.24	36.84	33.09	33.75	27.56	24.75	23.23	22.72	20.93	20.28	19.23	19.18	18.16	17.20	16.96	16.88	16.47	16.13	15.92	15.46	14.95	-4.9%

1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, Methodology for Allocating Municipal Solid Waste to Biogenic and Nono-Biogenic Energy, (Washington, DC, May 2007).
5/ Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal solid waste, landfill gas, other biomass, solar, and wind power.
6/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
7/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
8/ Includes refinery gas and still gas.
9/ Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), Annual Energy Review 2006, DOE/EIA-0384(2006) (Washington, DC, June 2007) and supporting databases. 2005 and 2006 prices: EIA, AEO2008 National Energy Modeling System run aeo2008.d030208f. Projections: EIA, AEO2008 National Energy Modeling System run aeo2008.d030208f.

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Table 8. Electricity Supply, Disposition, Prices, and Emissions
(billion kilowatthours, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2005-2030
Net Generation by Fuel Type																												
Electric Power Sector 1/																												
Power Only 2/																												
Coal	1921	1956	1971	1991	1995	2029	2090	2118	2142	2169	2212	2233	2266	2297	2322	2364	2418	2481	2548	2625	2697	2766	2845	2927	3012	3099	3191	2.0%
Petroleum	111	111	71	78	79	80	82	84	87	92	93	89	90	89	89	88	89	88	89	90	91	91	91	91	93	92	92	-0.7%
Natural Gas 3/	491	546	590	596	659	673	658	678	700	718	724	756	768	758	764	766	776	765	752	733	719	702	685	671	649	622	609	0.4%
Nuclear Power	789	780	787	795	792	788	789	792	804	806	808	812	826	846	867	881	885	886	886	886	886	886	886	892	899	906	896	0.6%
Pumped Storage/Other	-8	-7	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	1.1%
Renewable Sources 4/	321	319	359	386	399	416	426	432	431	434	436	440	442	446	447	447	445	445	448	451	456	458	459	461	462	459	461	1.5%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	3	4	4	5	5	N/A
Total	3624	3705	3770	3837	3915	3976	4037	4095	4156	4210	4264	4322	4383	4429	4480	4538	4605	4658	4716	4778	4842	4897	4961	5037	5111	5174	5245	1.4%
Combined Heat and Power 5/																												
Coal	36	37	32	32	31	31	31	31	31	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	-1.0%
Petroleum	5	5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-5.3%
Natural Gas	137	129	130	131	137	140	137	136	140	142	143	145	146	144	144	143	142	141	140	137	133	132	130	127	124	124	123	-0.2%
Renewable Sources	4	4	3	4	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	0.1%
Total	185	178	167	168	173	176	172	172	176	176	177	179	180	178	177	177	176	175	173	171	167	166	164	160	158	157	157	-0.5%
Total Net Generation	3808	3883	3937	4005	4088	4152	4209	4267	4332	4386	4441	4501	4563	4606	4658	4715	4781	4832	4889	4949	5009	5063	5124	5198	5269	5331	5402	1.3%
Less Direct Use	35	35	34	34	34	34	34	35	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	-0.1%
Net Available to the Grid	3773	3849	3903	3970	4054	4117	4175	4232	4298	4352	4407	4467	4529	4573	4624	4682	4747	4799	4856	4915	4976	5029	5091	5164	5235	5298	5368	1.3%
End-Use Generation 6/																												
Coal	22	22	22	22	22	22	22	29	30	30	33	33	33	35	37	39	41	43	53	55	67	85	98	98	105	107	110	6.6%
Petroleum	6	6	6	11	11	11	11	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	3.4%
Natural Gas	82	77	77	86	90	94	97	102	105	109	113	117	121	126	131	136	142	147	152	159	164	169	176	181	187	194	200	3.9%
Other Gaseous Fuels 7/	6	5	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	0.8%
Renewable Sources 4/	37	34	35	36	36	36	37	38	38	39	40	40	41	42	42	43	44	44	45	46	47	48	49	50	52	53	54	1.9%
Other 8/	14	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0.0%
Total	167	155	155	170	175	178	183	197	202	207	215	220	224	231	240	247	256	264	281	290	308	332	354	360	374	385	395	3.8%
Less Direct Use	136	126	125	134	137	140	144	152	156	160	165	168	172	177	182	187	194	199	208	215	224	236	248	253	261	269	276	3.2%
Total Sales to the Grid	31	29	30	36	37	38	39	45	46	47	50	51	52	55	57	60	62	65	72	75	84	96	106	107	113	116	119	5.9%
Total Electricity Generation	3975	4038	4092	4175	4263	4330	4392	4464	4534	4593	4656	4721	4787	4838	4897	4962	5037	5097	5170	5239	5317	5395	5478	5558	5643	5716	5797	1.5%
Total Net Generation to the Grid	3804	3877	3933	4007	4091	4155	4214	4277	4344	4399	4458	4519	4582	4627	4681	4741	4810	4864	4928	4990	5059	5125	5197	5271	5348	5413	5487	1.4%
Net Imports	11	25	27	17	15	6	11	10	11	14	12	8	10	13	11	14	11	12	12	13	14	13	13	13	13	13	13	-2.6%
Electricity Sales by Sector																												
Residential	1294	1365	1386	1402	1434	1457	1483	1506	1533	1550	1571	1591	1616	1632	1653	1675	1701	1715	1736	1756	1781	1797	1818	1839	1863	1878	1896	1.3%
Commercial	1229	1267	1280	1305	1344	1372	1398	1429	1460	1490	1520	1548	1577	1605	1634	1663	1694	1726	1759	1794	1828	1864	1902	1941	1980	2021	2062	2.0%
Industrial	1018	1021	1021	1043	1050	1054	1063	1071	1081	1089	1095	1103	1110	1111	1112	1118	1123	1128	1135	1139	1145	1155	1163	1174	1183	1190	1199	0.6%
Transportation	7	7	8	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	10	11	11	11	11	11	11	12	1.8%
Total	3548	3660	3694	3757	3836	3891	3953	4014	4082	4138	4194	4251	4312	4358	4408	4466	4528	4580	4641	4699	4765	4827	4894	4965	5038	5099	5168	1.4%
Direct Use	171	161	159	168	172	175	178	187	190	193	199	202	206	211	216	221	228	233	242	249	258	270	282	287	295	303	310	2.6%
Total Electricity Use	3719	3821	3853	3925	4008	4066	4132	4201	4272	4332	4393	4453	4518	4569	4624	4687	4756	4813	4882	4948	5023	5097	5176	5251	5332	5402	5478	1.5%
End-Use Prices (2005 cents per kilowatthour)																												
Residential	9.2	9.4	9.4	9.4	9.3	9.3	9.2	9.0	9.0	8.9	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	-0.1%
Commercial	8.4	8.6	8.8	8.6	8.6	8.5	8.4	8.1	8.1	8.0	8.0	8.0	8.0	8.1	8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.3	8.3	8.2	8.3	8.3	8.3	-0.2%
Industrial	5.4	5.7	6.2	6.4	6.4	6.3	6.1	5.9	5.7	5.7	5.6	5.6	5.7	5.7	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	0.2%
Transportation	8.9	8.6	8.9	8.7	8.8	8.7	8.5	8.3	8.2	8.2	8.1	8.1	8.1	8.2	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.4	8.3	-0.1%
All Sectors Average	7.9	8.1	8.3	8.3	8.3	8.2	8.1	7.9	7.8	7.7	7.7	7.7	7.7	7.8	7.9	7.9	7.9	7.9	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.1	0.0%
Prices by Service Category 9/ (2005 cents per kilowatthour)																												
Generation	5.2	5.4	5.7	5.7	5.7	5.6	5.4	5.2	5.1	5.1	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	0.0%
Transmission	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.0%
Distribution	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	-0.3%
Electric Power Sector Emissions 1/																												
Sulfur Dioxide (million tons)	10.26	10.21	10.19	9.96	8.89	7.89	6.56	5.70	5.24	5.02	4.80	4.46	4.30	4.15	4.01	3.94	3.90	3.88	3.83	3.80	3.75	3.68	3.66	3.63	3.63	3.61	3.63	-4.1%
Nitrogen Oxide (million tons)	3.75	3.60	3.89	3.82	3.85	2.41	2.41	2.44	2.41	2.43	2.44	2.20	2.19	2.21	2.21	2.21	2.22	2.23	2.23	2.24	2.25	2.25	2.26	2.27	2.27	2.28	2.28	-1.8%
Mercury (tons)	47.15	51.25	51.81	51.99	50.30	48.55	37.21	37.10	35.20	33.66	28.15	24.64	23.37	22.64	20.78	20.08	19.24	18.88	18.34	17.76	17.57	16.86	16.55	16.19	16.12	15.84	15.48	-4.7%

1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
5/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
7/ Includes refinery gas and still gas.
8/ Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006) and supporting databases. 2004 and 2005 prices: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a. Projections: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.

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Table 8. Electricity Supply, Disposition, Prices, and Emissions
(billion kilowatthours, unless otherwise noted)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average Annual Growth 2004-2030
Net Generation by Fuel Type																													
Electric Power Sector 1/																													
Power Only 2/																													
Coal	1916	1916	1986	1999	2037	2080	2137	2164	2174	2199	2198	2204	2209	2235	2269	2312	2354	2405	2454	2517	2583	2658	2728	2805	2897	3000	3100	3178	2.0%
Petroleum	111	110	107	102	86	87	88	90	89	91	92	92	89	88	88	88	91	90	92	92	91	92	93	96	98	99	99	99	-0.4%
Natural Gas 3/	439	486	527	497	503	523	514	533	565	619	668	702	743	769	784	802	815	814	813	800	794	785	775	761	740	720	693	691	1.4%
Nuclear Power	764	789	774	787	806	807	808	809	810	811	811	818	829	843	857	866	870	871	871	871	871	871	871	871	871	871	871	871	0.4%
Pumped Storage/Other	-9	-8	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	0.3%
Renewable Sources 4/	322	319	337	378	409	412	417	432	431	428	433	438	445	452	456	456	460	465	468	475	478	484	486	491	493	496	497	500	1.7%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	2	2	2	2	N/A
Total	3543	3612	3723	3754	3831	3900	3956	4020	4061	4140	4193	4246	4306	4378	4445	4516	4582	4638	4690	4745	4808	4881	4945	5016	5092	5178	5252	5332	1.5%
Combined Heat and Power 5/																													
Coal	37	38	32	32	31	31	31	30	30	31	31	30	30	30	30	30	30	30	30	30	30	30	29	29	29	28	28	27	-1.3%
Petroleum	5	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-2.8%
Natural Gas	129	132	139	138	130	137	139	140	144	149	153	157	159	161	159	156	157	153	152	149	145	143	141	141	139	135	133	131	-0.1%
Renewable Sources	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-0.3%
Total	177	182	177	176	167	174	175	176	180	186	190	194	195	196	195	192	194	189	188	185	181	179	177	176	174	169	167	164	-0.4%
Total Net Generation	3720	3794	3901	3930	3998	4074	4131	4196	4241	4326	4383	4440	4501	4574	4640	4708	4775	4827	4877	4931	4989	5060	5121	5193	5266	5347	5419	5497	1.4%
Less Direct Use	27	26	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	0.3%
Net Available to the Grid	3694	3768	3873	3902	3970	4046	4103	4168	4212	4298	4355	4412	4473	4546	4612	4680	4747	4799	4849	4903	4961	5032	5093	5165	5238	5319	5391	5469	1.4%
Commercial and Industrial Generation 6/																													
Coal	21	23	23	23	23	23	23	23	27	31	35	36	38	40	43	47	50	70	89	106	118	130	139	151	159	166	175	175	8.2%
Petroleum	5	5	6	6	11	11	12	12	13	14	12	13	13	13	13	13	13	14	13	13	13	13	13	13	13	13	13	13	3.9%
Natural Gas	83	83	85	87	93	95	98	101	104	107	109	112	116	120	123	127	130	134	138	142	145	149	152	156	159	162	165	169	2.8%
Other Gaseous Fuels 7/	7	5	5	5	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0.3%
Renewable Sources 4/	35	35	35	36	37	38	39	40	41	41	42	42	43	43	44	45	45	46	47	47	48	49	50	51	52	53	54	55	1.8%
Other 8/	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.0%
Total	162	161	165	168	179	182	187	192	200	208	214	220	226	232	240	247	255	280	302	324	340	357	370	387	399	411	424	429	3.8%
Less Direct Use	137	135	138	139	143	145	147	149	152	155	158	161	163	166	170	173	177	186	196	205	211	218	224	231	236	241	247	250	2.4%
Total Sales to the Grid	24	26	27	29	37	38	41	43	48	53	55	59	62	66	70	74	78	94	106	120	129	138	146	156	163	170	177	179	7.7%
Total Electricity Generation	3882	3955	4066	4098	4178	4256	4318	4388	4440	4534	4596	4660	4727	4807	4880	4955	5030	5108	5180	5255	5329	5417	5491	5579	5665	5758	5843	5926	1.6%
Total Net Generation to the Grid	3718	3793	3900	3931	4007	4083	4143	4211	4260	4350	4410	4471	4536	4612	4682	4754	4825	4893	4956	5022	5090	5171	5240	5321	5401	5489	5569	5648	1.5%
Net Imports	6	11	22	16	9	17	20	22	23	23	21	22	23	21	18	18	13	14	14	14	16	14	15	14	14	14	14	14	0.9%
Electricity Sales by Sector																													
Residential	1273	1293	1343	1353	1377	1411	1436	1461	1485	1511	1529	1552	1576	1602	1621	1643	1665	1691	1706	1726	1746	1770	1787	1808	1830	1857	1875	1897	1.5%
Commercial	1200	1229	1280	1286	1322	1362	1397	1430	1464	1498	1529	1560	1592	1626	1660	1694	1728	1762	1796	1832	1870	1907	1944	1984	2023	2066	2109	2151	2.2%
Industrial	1008	1021	1028	1036	1042	1049	1052	1060	1072	1080	1087	1095	1103	1113	1123	1135	1143	1147	1156	1164	1172	1184	1195	1209	1224	1238	1251	1262	0.8%
Transportation	25	25	25	25	25	26	26	26	27	27	27	27	28	28	28	28	29	29	29	29	30	30	30	30	31	31	31	31	0.9%
Total	3505	3567	3675	3700	3767	3847	3911	3978	4047	4116	4173	4234	4300	4370	4433	4501	4564	4629	4688	4751	4817	4891	4956	5032	5108	5191	5266	5341	1.6%
Direct Use	164	161	166	167	171	173	175	177	180	183	186	189	192	194	198	201	205	214	224	233	239	246	252	259	264	269	275	278	2.1%
Total Consumption	3669	3729	3840	3867	3937	4020	4085	4155	4227	4299	4359	4423	4491	4564	4630	4702	4768	4844	4912	4984	5056	5137	5208	5291	5372	5460	5541	5619	1.6%
End-Use Prices (2004 cents per kilowatthour)																													
Residential	8.9	8.9	9.8	9.5	8.9	8.6	8.5	8.5	8.4	8.3	8.4	8.4	8.3	8.3	8.3	8.3	8.4	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.5	8.4	8.5	8.5	-0.2%
Commercial	8.2	8.0	8.7	8.6	8.2	7.9	7.8	7.6	7.5	7.4	7.5	7.5	7.4	7.4	7.4	7.4	7.5	7.5	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.8	-0.1%
Industrial	5.3	5.3	6.0	6.0	5.9	5.7	5.5	5.3	5.2	5.1	5.2	5.2	5.1	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	0.1%
Transportation	7.4	7.4	7.8	8.0	7.5	7.2	7.1	7.1	7.0	7.0	7.0	7.0	6.9	6.9	6.9	7.0	7.0	7.0	7.1	7.1	7.0	7.1	7.1	7.1	7.1	7.1	7.1	7.2	-0.1%
All Sectors Average	7.6	7.6	8.3	8.2	7.8	7.6	7.4	7.3	7.2	7.1	7.2	7.2	7.1	7.1	7.1	7.2	7.3	7.2	7.3	7.3	7.3	7.3	7.4	7.4	7.4	7.4	7.4	7.5	0.0%
Prices by Service Category (2004 cents per kilowatthour)																													
Generation	5.0	5.0	5.8	5.6	5.3	5.0	4.9	4.7	4.6	4.6	4.7	4.7	4.6	4.6	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.9	5.0	5.0	5.0	5.0	5.0	5.1	0.1%
Transmission	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.9%
Distribution	2.1	2.1	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-0.6%
Electric Power Sector Emissions 1/																													
Sulfur Dioxide (million tons)	10.60	10.89	10.74	10.32	9.29	8.01	6.55	5.91	5.54	5.25	4.96	4.80	4.63	4.45	4.31	4.19	4.11	4.04	3.94	3.91	3.86	3.82	3.80	3.78	3.75	3.75	3.73	3.72	-4.0%
Nitrogen Oxide (million tons)	4.12	3.74	3.90	3.75	3.79	3.90	2.37	2.34	2.36	2.38	2.39	2.33	2.10	2.09	2.10	2.11	2.12	2.13	2.13	2.13	2.14	2.15	2.16	2.16	2.18	2.19	2.17	2.17	-2.1%
Mercury (tons)	50.70	53.31	53.64	52.70	52.60	50.95	48.90	37.73	37.68	36.99	32.81	30.65	24.04	22.25	21.76	20.76	19.68	18.74	18.61	18.28	17.60	17.06	16.59	16.41	15.88	15.40	15.24	15.31	-4.7%

1/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
5/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
7/ Other gaseous fuels include refinery and still gas.
8/ Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), Annual Energy Review 2004, DOE/EIA-0384(2004) (Washington, DC, August 2005) and supporting databases. 2003 and 2004 commercial and transportation electricity sales based on: EIA, Annual Energy Review 2004, DOE/EIA-0384(2004) (Washington, DC, August 2005) and Oak Ridge National Laboratory, Transportation Energy Data Book 24 (Oak Ridge, TN, December 2004). 2003 and 2004 prices: EIA, AEO2006 National Energy Modeling System run aeo2006.d111905a. Projections: EIA, AEO2006 National Energy Modeling System run aeo2006.d111905a.

Table 8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2003-2025
Net Generation by Fuel Type																									
Electric Power Sector 1/																									
Power Only 2/																									
Coal	1881	1916	1939	2004	2049	2107	2141	2160	2169	2179	2196	2211	2231	2251	2277	2309	2344	2384	2440	2503	2579	2673	2753	2836	1.8%
Petroleum	83	106	107	109	109	112	108	111	112	113	113	114	118	118	117	115	119	124	124	126	126	125	125	128	0.9%
Natural Gas 3/	457	407	451	446	451	470	528	583	634	688	734	774	815	854	900	949	991	1018	1038	1040	1042	1037	1051	1048	4.4%
Nuclear Power	780	764	795	796	800	808	810	811	813	814	817	821	823	826	828	830	830	830	830	830	830	830	830	830	0.4%
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	0.1%
Renewable Sources 4/	311	318	327	366	380	383	384	387	389	389	390	392	394	398	401	402	405	408	412	415	418	421	426	430	1.4%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	3	3	N/A
Total	3503	3501	3611	3713	3780	3872	3964	4043	4109	4174	4242	4303	4373	4438	4515	4598	4681	4757	4836	4907	4989	5079	5180	5267	1.9%
Combined Heat and Power 5/																									
Coal	31	34	28	30	31	32	33	33	33	33	33	34	34	34	34	34	34	34	34	33	33	33	34	33	-0.1%
Petroleum	7	7	3	6	5	5	5	5	6	6	6	6	6	7	7	7	7	7	7	7	7	7	7	7	0.1%
Natural Gas	151	149	177	171	170	173	179	183	188	190	196	198	201	200	198	197	197	197	196	195	193	189	189	186	1.0%
Renewable Sources	6	6	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-1.7%
Total	197	197	213	210	210	214	222	225	230	233	238	242	245	244	242	242	241	242	240	240	237	233	234	230	0.7%
Total Net Generation	3700	3699	3824	3923	3990	4086	4185	4268	4339	4407	4480	4545	4618	4683	4757	4840	4922	4998	5076	5146	5226	5312	5414	5497	1.8%
Less Direct Use	50	50	65	65	65	66	66	66	66	66	65	65	65	65	65	65	65	65	65	65	65	65	65	65	1.2%
Net Available to the Grid	3650	3649	3759	3857	3925	4020	4120	4202	4273	4342	4415	4480	4553	4617	4691	4774	4857	4933	5011	5081	5161	5246	5348	5432	1.8%
Commercial and Industrial Generation 6/																									
Coal	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	N/A
Petroleum	5	6	6	6	7	7	8	9	9	9	9	9	9	10	10	10	11	11	12	13	13	13	13	13	3.8%
Natural Gas	83	76	80	81	88	90	93	97	100	103	107	110	114	117	121	126	130	135	141	146	152	157	163	169	3.7%
Other Gaseous Fuels 7/	6	6	6	6	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-0.4%
Renewable Sources 4/	34	35	38	39	40	40	41	42	43	43	44	44	45	45	46	46	47	49	50	51	52	53	54	55	2.0%
Other 8/	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0.0%
Total	159	153	160	163	169	172	177	182	187	191	195	199	203	208	213	218	224	231	238	245	252	259	266	273	2.7%
Less Direct Use	131	126	129	130	131	132	134	137	139	140	142	144	146	149	151	154	157	160	164	167	171	174	178	182	1.7%
Total Sales to the Grid	28	28	31	33	38	40	43	46	48	50	52	54	57	59	61	64	67	71	74	78	81	84	87	91	5.5%
Total Electricity Generation	3860	3852	3984	4086	4160	4258	4363	4450	4526	4598	4675	4744	4821	4890	4969	5058	5146	5229	5314	5392	5478	5570	5679	5770	1.9%
Total Net Generation to the Grid	3678	3677	3790	3890	3963	4060	4163	4248	4322	4392	4467	4534	4609	4676	4753	4839	4924	5004	5085	5159	5242	5331	5436	5522	1.9%
Net Imports	22	5	4	5	7	5	6	7	9	16	18	16	17	21	21	15	14	14	15	15	15	16	10	11	4.1%
Electricity Sales by Sector																									
Residential	1267	1280	1288	1333	1356	1387	1422	1446	1471	1495	1521	1540	1561	1584	1609	1628	1649	1670	1696	1713	1737	1761	1790	1810	1.6%
Commercial	1208	1210	1229	1262	1300	1343	1387	1427	1466	1504	1541	1577	1613	1651	1691	1733	1774	1814	1854	1897	1942	1989	2038	2088	2.5%
Industrial	972	969	1007	1030	1042	1058	1079	1098	1107	1120	1131	1140	1157	1166	1172	1187	1204	1217	1229	1238	1248	1260	1274	1286	1.3%
Transportation	22	23	23	24	24	25	25	26	26	27	27	28	28	29	29	30	31	31	32	32	33	34	34	35	2.0%
Total	3469	3481	3547	3649	3722	3813	3912	3997	4070	4145	4220	4285	4360	4430	4501	4577	4657	4732	4811	4880	4959	5044	5136	5220	1.9%
Direct Use	182	175	194	196	196	198	200	202	204	206	208	210	212	214	216	219	222	226	229	233	236	240	244	248	1.6%
Total Consumption	3651	3657	3741	3845	3918	4011	4112	4199	4274	4351	4428	4494	4572	4644	4718	4797	4880	4958	5040	5113	5195	5284	5380	5467	1.8%
End-Use Prices 9/ (2003 cents per kilowatthour)																									
Residential	8.6	8.7	8.6	8.6	8.3	8.0	7.8	7.9	7.8	7.8	7.9	8.0	8.0	8.1	8.0	8.1	8.1	8.2	8.2	8.3	8.3	8.2	8.2	8.3	-0.2%
Commercial	8.0	7.9	7.9	7.8	7.5	7.1	6.9	6.8	6.8	6.8	6.9	7.0	7.2	7.3	7.3	7.3	7.4	7.5	7.5	7.6	7.6	7.6	7.6	7.6	-0.2%
Industrial	5.0	5.1	5.4	5.3	5.1	4.9	4.8	4.8	4.7	4.7	4.7	4.8	4.9	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.3	5.3	5.3	5.4	0.2%
Transportation	6.8	7.0	7.2	7.1	6.8	6.5	6.4	6.4	6.4	6.4	6.5	6.6	6.7	6.7	6.7	6.7	6.7	6.8	6.8	6.8	6.8	6.8	6.8	6.8	-0.2%
All Sectors Average	7.4	7.4	7.4	7.4	7.1	6.8	6.7	6.6	6.6	6.6	6.7	6.8	6.9	6.9	7.0	7.0	7.1	7.2	7.2	7.3	7.2	7.2	7.3	7.3	-0.1%
Prices by Service Category 9/ (2003 cents per kilowatthour)																									
Generation	4.7	4.8	4.9	4.8	4.6	4.3	4.1	4.1	4.1	4.1	4.2	4.3	4.4	4.5	4.5	4.5	4.6	4.7	4.7	4.8	4.8	4.8	4.9	4.9	0.1%
Transmission	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.0%
Distribution	2.1	2.1	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-0.7%
Electric Power Sector Emissions 1/																									
Sulfur Dioxide (million tons)	10.19	10.59	10.70	11.05	10.90	10.72	10.30	9.61	9.29	9.22	9.10	8.99	9.01	8.97	9.01	8.99	9.00	8.95	8.95	8.95	8.95	8.95	8.95	8.95	-0.8%
Nitrogen Oxide (million tons)	4.37	4.12	3.57	3.63	3.70	3.80	3.90	3.96	3.99	4.02	4.04	4.06	4.08	4.09	4.11	4.13	4.14	4.16	4.18	4.19	4.21	4.24	4.26	4.29	0.2%
Mercury (tons)	50.08	49.70	50.38	51.99	52.30	52.91	53.01	54.06	54.08	54.68	54.74	54.74	55.10	55.12	55.46	55.61	55.71	55.58	55.45	54.69	54.91	55.10	55.27	55.97	0.5%

1/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
5/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
7/ Other gaseous fuels include refinery and still gas.
8/ Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
9/ Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), Annual Energy Review 2003, DOE/EIA-0384(2003) (Washington, DC, September 2004) and supporting databases. 2002 and 2003 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, Transportation Energy Data Book 21 (Oak Ridge, TN, November 2001). 2002 and 2003 prices: EIA, AEO2005 National Energy Modeling System run aeo2005.d102004a. Projections: EIA, AEO2005 National Energy Modeling System run aeo2005.d102004a.

Table 8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2002-2025
Generation by Fuel Type																										
Electric Power Sector 1/																										
Power Only 2/																										
Coal	1852	1875	1944	1947	2002	2057	2110	2131	2173	2201	2222	2244	2265	2288	2318	2353	2395	2435	2493	2560	2634	2724	2830	2891	2975	2.0%
Petroleum	113	77	95	51	62	61	64	71	68	62	69	82	88	96	103	101	100	92	87	82	87	82	75	78	77	0.0%
Natural Gas 3/	427	450	420	504	505	524	537	577	597	642	681	717	755	791	814	854	891	935	961	972	962	959	948	969	969	3.4%
Nuclear Power	769	780	762	779	791	794	795	796	791	794	800	803	806	809	812	814	816	816	816	816	816	816	816	816	816	0.2%
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9	0.3%
Renewable Sources 4/	259	304	339	374	379	383	389	392	396	400	405	408	412	416	420	423	426	429	434	442	448	450	452	456	460	1.8%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	2	2	3	3	4	4	5	5	5	N/A
Non-Utility Generation for Own Use	-20	-34	-39	-40	-40	-40	-40	-40	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	0.4%
Total	3391	3443	3512	3606	3690	3770	3845	3918	3977	4054	4129	4206	4279	4352	4423	4500	4583	4663	4747	4829	4906	4989	5079	5169	5257	1.9%
Combined Heat and Power 5/																										
Coal	31	32	28	29	30	32	33	33	33	33	33	33	34	34	34	34	33	33	33	33	33	33	33	33	33	0.1%
Petroleum	6	6	2	0	0	0	1	1	1	1	2	2	3	4	5	4	4	3	3	2	3	3	2	2	2	-3.8%
Natural Gas	128	148	152	157	159	161	166	170	176	174	175	176	173	168	165	165	161	163	161	159	156	154	150	150	149	0.0%
Renewable Sources	4	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-0.7%
Non-Utility Generation for Own Use	-9	-11	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	-24	3.6%
Total	160	183	163	166	170	173	180	184	191	188	189	191	189	185	183	183	179	179	177	175	172	169	165	166	164	-0.5%
Net Available to the Grid	3551	3626	3674	3773	3860	3944	4025	4102	4167	4242	4318	4397	4468	4538	4606	4683	4762	4842	4924	5004	5077	5159	5244	5335	5421	1.8%
End-Use Sector Generation																										
Combined Heat and Power 6/																										
Coal	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	0.0%
Petroleum	6	5	5	5	8	9	10	10	11	12	13	13	14	14	15	15	15	16	17	17	17	17	17	17	18	5.6%
Natural Gas	83	84	84	86	89	94	97	100	105	109	114	118	121	125	129	133	137	142	147	153	158	163	169	175	181	3.4%
Other Gaseous Fuels 7/	4	5	6	6	8	8	8	9	9	9	10	10	10	10	11	11	11	12	12	12	12	12	13	13	13	4.3%
Renewable Sources 4/	29	30	31	32	34	35	36	37	38	39	40	41	43	44	45	46	47	48	49	50	51	52	52	53	54	2.6%
Other 8/	9	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0.0%
Total	151	157	158	162	172	178	183	188	195	202	208	215	220	226	231	237	243	250	257	264	271	277	284	291	299	2.8%
Other End-Use Generators 9/	3	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	7	1.9%
Generation for Own Use	-129	-134	-134	-136	-144	-147	-149	-152	-155	-158	-161	-164	-167	-170	-173	-176	-179	-182	-186	-190	-193	-197	-201	-206	-210	2.0%
Total Sales to the Grid	25	27	28	31	32	35	38	41	45	48	52	55	58	61	63	66	69	73	76	80	83	86	88	92	95	5.6%
Total Electricity Generation	3734	3831	3900	4003	4100	4191	4276	4359	4428	4510	4593	4678	4755	4830	4904	4987	5071	5159	5247	5335	5415	5503	5595	5693	5787	1.8%
Net Imports	22	22	40	30	32	29	28	28	29	31	32	31	31	30	32	30	27	24	20	21	17	13	11	9	8	-4.6%
Electricity Sales by Sector																										
Residential	1203	1268	1282	1302	1319	1338	1360	1386	1405	1428	1450	1474	1490	1510	1531	1554	1571	1592	1615	1641	1657	1678	1701	1729	1747	1.4%
Commercial	1197	1208	1213	1254	1296	1335	1372	1408	1443	1480	1517	1552	1587	1621	1653	1684	1718	1754	1792	1828	1862	1895	1929	1965	2003	2.2%
Industrial	964	994	978	1003	1030	1053	1073	1089	1103	1120	1140	1159	1180	1197	1216	1235	1256	1276	1292	1310	1327	1348	1372	1395	1422	1.6%
Transportation	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29	30	30	31	31	32	33	33	34	35	35	2.1%
Total	3386	3492	3495	3582	3669	3750	3830	3909	3977	4055	4133	4212	4285	4357	4429	4502	4576	4653	4730	4811	4879	4955	5036	5123	5207	1.8%
End-Use Prices 10/ (2002 cents per kilowatthour)																										
Residential	8.7	8.4	8.5	8.3	8.2	8.1	8.0	8.0	8.0	7.9	7.9	8.0	8.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	-0.2%
Commercial	8.0	7.8	7.6	7.4	7.2	7.0	6.9	6.9	7.0	7.0	7.0	7.1	7.0	7.1	7.2	7.2	7.2	7.2	7.2	7.2	7.3	7.3	7.2	7.3	7.3	-0.3%
Industrial	5.2	5.0	4.8	4.7	4.6	4.6	4.5	4.6	4.6	4.6	4.5	4.6	4.6	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.7	4.8	4.8	-0.2%
Transportation	7.4	7.2	7.3	7.1	6.9	6.7	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.9	6.9	6.9	6.9	6.9	6.8	6.8	6.9	6.8	6.8	6.8	6.8	-0.2%
All Sectors Average	7.4	7.2	7.1	7.0	6.8	6.7	6.6	6.6	6.7	6.6	6.6	6.7	6.7	6.8	6.8	6.9	6.8	6.9	6.8	6.9	6.9	6.9	6.8	6.9	6.9	-0.2%
Prices by Service Category 10/ (2002 cents per kilowatthour)																										
Generation	4.8	4.6	4.6	4.4	4.3	4.2	4.2	4.1	4.2	4.1	4.1	4.2	4.2	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	-0.1%
Transmission	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.9%
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	-0.7%
Electric Power Sector Emissions 1/																										
Sulfur Dioxide (million tons)	10.63	10.54	10.62	10.80	10.18	9.90	10.13	10.30	9.93	9.90	9.86	9.37	9.15	9.09	8.95	8.95	8.95	8.94	8.95	8.94	8.94	8.94	8.94	8.95	8.95	-0.7%
Nitrogen Oxide (million tons)	4.75	4.39	3.70	3.23	3.28	3.36	3.43	3.46	3.48	3.50	3.52	3.54	3.56	3.57	3.60	3.63	3.65	3.64	3.65	3.67	3.66	3.68	3.71	3.73	3.75	-0.7%
Mercury (tons)	49.14	50.95	50.87	49.95	50.12	50.78	52.14	52.26	52.33	52.20	52.81	52.84	52.45	52.45	52.65	53.24	53.19	53.02	53.17	53.59	53.74	53.72	53.87	53.97	54.37	0.3%

1/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
5/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
7/ Other gaseous fuels include refinery and still gas.
8/ Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
9/ Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
10/ Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), Annual Energy Review 2002, DOE/EIA-0384(2002) (Washington, DC, October 2003) and supporting databases. 2001 and 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, Transportation Energy Data Book 21 (Oak Ridge, TN, November 2001). 2001 and 2002 prices: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. Projections: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Series Id: CUUR0000SA0,CUUS0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100

Year	Annual Avg.
2000	172.2
2001	177.1
2002	179.9
2003	184
2004	188.9
2005	195.3
2006	201.6
2007	207.342
2008	215.303

CPI Deflator	
2000	1
2001	0.972332016
2002	0.957198444
2003	0.935869565
2004	0.911593436
2005	0.88172043
2006	0.854166667
2007	0.830511908
2008	0.799803068

Table 9.1: Construction Expenditures for Transmission and Distribution

Shareholder-Owned Electric Utilities *

Millions of Dollars, Nominal & Real | 1977 - 2006

Nominal Dollars

	1977r	1978r	1979r	1980r	1981r	1982r	1983r	1984r	1985r	1986r
Transmission……	1,687	1,738	2,090	2,353	2,270	2,203	2,371	2,250	1,863	1,761
Distribution……..	3,390	3,875	4,334	4,483	4,606	4,827	5,021	5,899	6,590	7,248
Total T&D………	**5,077**	**5,613**	**6,424**	**6,836**	**6,876**	**7,030**	**7,392**	**8,149**	**8,453**	**9,009**

	1987r	1988r	1989r	1990r	1991r	1992r	1993	1994	1995	1996
Transmission……	2,066	1,942	2,512	2,441	2,294	2,610	2,638	2,524	2,128	2,267
Distribution……..	7,457	8,224	8,685	9,100	8,780	8,653	9,017	9,195	8,316	8,368
Total T&D………	**9,523**	**10,166**	**11,197**	**11,541**	**11,074**	**11,263**	**11,655**	**11,719**	**10,444**	**10,635**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006p
Transmission……	1,962	1,994	2,326	3,463	3,649	3,789	4,130	4,589	5,808	6,909
Distribution……..	8,709	10,262	10,385	10,633	11,283	11,797	11,622	13,080	14,562	17,312
Total T&D………	**10,671**	**12,256**	**12,711**	**14,096**	**14,932**	**15,586**	**15,752**	**17,669**	**20,370**	**24,221**

See Footnotes below.

Real Dollars (2006 Dollars)

	1977r	1978r	1979r	1980r	1981r	1982r	1983r	1984r	1985r	1986r
Transmission……	5,166	5,164	5,723	5,817	5,188	4,784	5,014	4,719	3,866	3,625
Distribution……..	9,673	10,509	10,696	10,253	9,609	9,453	9,582	11,146	12,426	13,599
Total T&D………	**14,839**	**15,674**	**16,418**	**16,069**	**14,798**	**14,237**	**14,596**	**15,865**	**16,292**	**17,224**

	1987r	1988r	1989r	1990r	1991r	1992r	1993r	1994r	1995r	1996r
Transmission……	4,232	3,622	4,463	4,181	3,859	4,354	4,254	3,886	3,137	3,283
Distribution……..	13,914	14,527	14,629	14,908	14,159	13,813	14,101	13,964	12,215	12,171
Total T&D………	**18,146**	**18,149**	**19,093**	**19,089**	**18,018**	**18,167**	**18,355**	**17,850**	**15,351**	**15,455**

	1997r	1998r	1999r	2000r	2001r	2002r	2003r	2004r	2005r	2006p
Transmission……	2,800	2,763	3,274	4,580	4,696	4,812	5,232	5,319	6,308	6,909
Distribution……..	12,579	14,494	14,668	14,618	15,080	15,258	14,754	15,540	16,237	17,312
Total T&D………	**15,378**	**17,257**	**17,942**	**19,199**	**19,775**	**20,070**	**19,986**	**20,859**	**22,545**	**24,221**

Note: Real dollar results are shown using the Handy-Whitman Index of Public Utility Construction Costs to adjust for inflation from year to year. Please see Table 10.4: Cost Trends of Electric Utility Construction, on page 119 of this publication.

p Preliminary r Revised.

* Represents 65 shareholder-owned electric companies (both vertically integrated and stand-alone transmission companies) whose stock is publicly traded on major U.S. stock exchanges. Also included are three additional companies who provide regulated electric service in the United States but are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

Sources: Prior to 1999, data are from Edison Electric Institute's "Uniform Statistical Report". For 1999, data are from Edison Electric Institute's Construction Expenditures Survey, the Federal Energy Regulatory Commission (FERC), Annual Report of Major Electric Utilities (Form 1), and company Annual Reports (10-K). For 2000-2006, data are from Edison Electric Institute's Annual Property & Plant Capital Investment Survey and the Federal Energy Regulatory Commission (FERC), Annual Report of Major Electric Utilities (Form 1). The Handy-Whitman Index of Public Utility Construction Costs, courtesy of Whitman, Requardt and Associates, Baltimore, Maryland.

National Grid - Narragansett Electric Company

Summary of Average Distribution Charges, by Rate Class for 2010, 2011 and 2012
Assuming All of Company Proposals are Approved by Commission

Line		Company (a)	A-16/A-60 (b)	C-06 (c)	G-02 (d)	G-32/G-62 (e)	STL (f)	X-01 (g)
		Rates for CY 2010						
1	Revenue Requirement Docket 4065	$280,241,000	$150,507,000	$28,473,000	$40,255,000	$46,572,000	$14,107,000	$327,000
2	forecasted kWh deliveries for 2010	7,662,969,000	3,037,613,000	552,429,000	1,371,694,000	2,606,916,000	68,382,000	25,935,000
3	Average distribution charges effective 1/1/2010	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
4	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
5	Pension Adj.	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
6	Total Average distribution charge	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
		Rates for CY 2011						
7	Actual Target Revenue for 2011	$283,111,899	$152,047,773	$28,764,746	$40,668,930	$47,037,399	$14,255,357	$337,702
8	forecasted kWh deliveries for 2011	7,874,058,477	3,079,099,181	584,046,208	1,378,180,130	2,736,870,649	69,927,072	25,935,238
9	Average distribution charges effective 1/1/2011	$0.03596	$0.04938	$0.04925	$0.02951	$0.01719	$0.20386	$0.01302
10	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
11	Pension Adj.	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
12	Total Average distribution charge	$0.03596	$0.04938	$0.04925	$0.02951	$0.01719	$0.20386	$0.01302
		Rates for CY 2012						
13	Actual Target Revenue for 2012	$292,821,954	$156,827,810	$29,681,586	$42,148,714	$49,149,208	$14,641,250	$373,406
14	forecasted kWh deliveries for 2012	8,106,768,760	3,145,439,618	612,163,672	1,387,592,383	2,866,333,426	69,304,423	25,935,238
15	Average distribution charges effective 1/1/2012	$0.03612	$0.04986	$0.04849	$0.03038	$0.01715	$0.21126	$0.01440
16	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
17	Pension Adj.	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
18	Total Average distribution charge	$0.03624	$0.04998	$0.04861	$0.03050	$0.01727	$0.21138	$0.01452

Line Notes

1 from Schedule NG-HSG-1, page 2 of 50, line 22
2 from Schedule NG-HSG-2, page 2 of 35, line 1
3 Line 1 ÷ Line 2, rounded to five decimal places
4 n/a for 2010
5 n/a for 2010
6 sum of Lines 3 through 5
7 from page 3, line 7
8 Company forecast for 2011, includes projected effect of DSM programs
9 Line 7 ÷ Line 8, rounded to five decimal places
10 from page 5 for 2011
11 from page 5 for 2011
12 sum of Lines 9 through 11
13 from page 4, line 22
14 Company forecast for 2012, includes projected effect of DSM programs
15 Line 13 ÷ Line 14, rounded to five decimal places
16 from page 5 for 2012
17 from page 5 for 2012
18 sum of Lines 15 through 17

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of RDM Revenue Adjustments

Line		(A) CY 2010	(B) CY 2011	(C) CY 2012
	Calculation of Annual Target Revenue (ATR)			
1	Revenue Requirement Docket 4065	$280,241,000	$280,241,000	$280,241,000
2	Net Inflation Adjustment		$1,697,274	$4,136,372
3	Prior Year RDR Plan Revenue Reconciliation		$0	$2,752,724
4	Cumulative Net Historic Capital Adjustment	$0	$3,926,349	$11,819,741
5	Annual Target Revenue	$280,241,000	$285,864,623	$298,949,837
		Rates for CY 2010	**Rates for CY 2011**	**Rates for CY 2012**
	Components of Billed Revenue			
6	Revenue Requirement Docket 4065	$280,241,000	$280,241,000	$280,241,000
7	Prior Year RDR Plan Revenue Reconciliation		$0	$2,752,724
8	Net Inflation Adjustment		$1,697,274	$4,136,372
9	Cumulative Net Historic Capital Adjustment - Prior Year		$0	$3,926,349
10	Current Year Capital Adjustment		$1,173,625	$1,765,509
11	Cumulative RDR Plan Adjustment Factor Revenue	$0	$2,870,899	$12,580,954
12	Total RDM Plan Revenue	$280,241,000	$283,111,899	$292,821,954
13	Incremental RDR Plan Adjustment Factor Revenue	$0	$2,870,899	$9,710,055
	Calculation of Annual RDM Reconciliation			
14	Actual Billed Revenue	$280,241,000	$283,111,899	$292,821,954
15	Annual Target Revenue	$280,241,000	$285,864,623	$298,949,837
16	Excess/(Under) billed Revenue	$0	($2,752,724)	($6,127,883)

Line Notes

1 For illustrative purposes, revenue requirement as shown on Schedule NG-HSG-2, page 2, line 22. (See the response to Division 2-3 for an explanation of the difference between the revenue requirement on Schedule NG-HSG-2 and the revenue requirement on NG-RLO-1.
2 As estimated on Schedule NG-RLO-7, page 2 of 4, Line 22
3 Prior year Line 16 x (-1)
4 As estimated on Schedule NG-RLO-7, page 3 of 4 Line 52 for Current Year
5 Sum of Lines 1 through 4
6 From Line 1
7 Prior year Line 15 x (-1) - Amount to be allocated over total forecasted kWh's
8 From Line 2 - Amount to be allocated to each class based on class O&M allocator
9 Prior Year Line 4 - Amount to be allocated to each class based on class rate base allocator
10 As estimated on Schedule NG-RLO-7, page 4 Line 37 for Current Year - Amount to be allocated to each class based on class rate base allocator
11 Sum of Lines 7 through 10
12 Line 6 + Line 11
13 Current Year Line 11 - Prior Year Line 11
14 From Line 12
15 From Line 5
16 Line 14 - Line 15

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of RDM Revenue Adjustment for 2011

Line		Company (a)	A-16/A-60 (b)	C-06 (c)	G-02 (d)	G-32/G-62 (e)	STL (f)	X-01 (g)
	Calculation of RDR Plan Revenue Adjustment for effect 1/1/2011	**Rates for CY 2011**						
1	Revenue Requirement Docket 4065	$280,241,000	$150,507,000	$28,473,000	$40,255,000	$46,572,000	$14,107,000	$327,000
2	Prior Year RDR Plan Revenue Reconciliation	$0	$0	$0	$0	$0	$0	$0
3	Net Inflation Adjustment	$1,697,274	$919,994	$171,668	$242,436	$270,721	$86,535	$5,928
4	Cumulative Net Historic Capital Adjustment - Prior Year	$0	$0	$0	$0	$0	$0	$0
5	Current Year Capital Adjustment	$1,173,625	$620,779	$120,078	$171,494	$194,679	$61,822	$4,774
6	Cumulative RDR Plan Adjustment Factor Revenue	$2,870,899	$1,540,773	$291,746	$413,930	$465,399	$148,357	$10,702
7	Total RDM Plan Revenue	$283,111,899	$152,047,773	$28,764,746	$40,668,930	$47,037,399	$14,255,357	$337,702
8	Incremental RDR Plan Adjustment Factor Revenue	$2,870,899	$1,540,773	$291,746	$413,930	$465,399	$148,357	$10,702
	Allocation Factors							
9	Rate Year Rate Base	$623,946	$330,031	$63,838	$91,173	$103,499	$32,867	$2,538
10	Rate Base Allocation Factor		52.89%	10.23%	14.61%	16.59%	5.27%	0.41%
11	Rate Year O&M Expense	$213,024	$115,468	$21,546	$30,428	$33,978	$10,861	$744
12	O&M Allocation Factor		54.20%	10.11%	14.28%	15.95%	5.10%	0.35%
13	forecasted kWh Deliveries for CY 2011	7,874,058,477	3,079,099,181	584,046,208	1,378,180,130	2,736,870,649	69,927,072	25,935,238

Line Notes

1 from page 2
2 from page 2, line 16 for CY 2010
3 column (a) from page 2, line 8 for CY 2011; columns (b) - (g): column (a) x line (12)
4 column (a) from page 2, line 9 for CY 2011; columns (b) - (g): column (a) x line (10)
5 column (a) from page 2, line 10 for CY 2011; columns (b) - (g): column (a) x line (10)
6 sum of lines 2 through 5
7 Line 1 + Line 6
8 Line 7 - Line 1
9 Schedule NG-HSG-1, page 2, line 16
10 Line 9 ÷ Line 9 column (a)
11 Schedule NG-HSG-1, page 2, line 28
12 Line 11 ÷ Line 11 column (a)
13 from Company forecast, including effect of proposed DSM programs

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of RDM Revenue Adjustment for 2012

Line		Company	A-16/A-60	C-06	G-02	G-32/G-62	STL	X-01
	Calculation of Annual RDM Reconciliation							
	Calculation of 2011 Annual Target Revenue (ATR) as Adjusted for Cumulative Net Cap Adj.							
1	Revenue Requirement Docket 4065	$280,241,000	$150,507,000	$28,473,000	$40,255,000	$46,572,000	$14,107,000	$327,000
2	Net Inflation Adjustment	$1,697,274	$919,994	$171,668	$242,436	$270,721	$86,535	$5,928
3	Prior Year RDR Plan Revenue Reconciliation	$0	$0	$0	$0	$0	$0	$0
4	Cumulative Net Historic Capital Adjustment	$3,926,349	$2,076,809	$401,718	$573,731	$651,295	$206,824	$15,971
5	Annual Target Revenue for 2011	$285,864,623	$153,503,804	$29,046,386	$41,071,167	$47,494,016	$14,400,360	$348,899
	Reconciliation of actual revenue for 2011 with ATR for 2011							
6	Actual Billed Revenue - CY 2011	$283,111,899	$152,047,773	$28,764,746	$40,668,930	$47,037,399	$14,255,357	$337,702
7	Annual Target Revenue - CY 2011	$285,864,623	$153,503,804	$29,046,386	$41,071,167	$47,494,016	$14,400,360	$348,899
8	Excess/(Under) billed Revenue	($2,752,724)	($1,456,030)	($281,640)	($402,237)	($456,617)	($145,003)	($11,197)
9	forecasted kWh deliveries for CY 2012	8,106,768,760						
10	RDM Prior Year Adj Factor effective 1/1/2012	$0.00033						
	Allocation Factors							
11	Rate Year Rate Base	$623,946	$330,031	$63,838	$91,173	$103,499	$32,867	$2,538
12	Rate Base Allocation Factor		52.89%	10.23%	14.61%	16.59%	5.27%	0.41%
13	Rate Year O&M Expense	$213,024	$115,468	$21,546	$30,428	$33,978	$10,861	$744
14	O&M Allocation Factor		54.20%	10.11%	14.28%	15.95%	5.10%	0.35%
15	forecasted kWh Deliveries for CY 2012	8,106,768,760	3,145,439,618	612,163,672	1,387,592,383	2,866,333,426	69,304,423	25,935,238
		Rates for CY 2012						
	Calculation of RDR Plan Revenue Adjustment for effect 1/1/2012							
16	Revenue Requirement Docket 4065	$280,241,000	$150,507,000	$28,473,000	$40,255,000	$46,572,000	$14,107,000	$327,000
17	Prior Year RDR Plan Revenue Reconciliation	$2,752,724	$1,068,061	$207,866	$471,169	$973,289	$23,533	$8,807
18	Net Inflation Adjustment	$4,136,372	$2,242,088	$418,367	$590,833	$659,764	$210,892	$14,447
19	Cumulative Net Historic Capital Adjustment - Prior Year	$3,926,349	$2,076,809	$401,718	$573,731	$651,295	$206,824	$15,971
20	Current Year Capital Adjustment	$1,765,509	$933,851	$180,635	$257,982	$292,859	$93,000	$7,181
21	Cumulative RDR Plan Adjustment Factor Revenue	$12,580,954	$6,320,810	$1,208,586	$1,893,714	$2,577,208	$534,250	$46,406
22	Total RDM Plan Revenue	$292,821,954	$156,827,810	$29,681,586	$42,148,714	$49,149,208	$14,641,250	$373,406
23	CY 2011 ATR	$283,111,899	$152,047,773	$28,764,746	$40,668,930	$47,037,399	$14,255,357	$337,702
24	Incremental RDR Plan Adjustment Factor Revenue	$9,710,055	$4,780,037	$916,840	$1,479,785	$2,111,808	$385,893	$35,704

Line Notes

1 from page 2
2 column (a) from page 2, line 2; columns (b) - (g): column (a) x line (14)
3 n/a
4 column (a) from page 2, line 3; columns (b) - (g): column (a) x line (12)
5 Sum of Lines 1 through 4
6 Actual revenue for CY 2011 - illustrative
7 Line 5
8 Line 6 - Line 7
9 Line 15
10 Line 8 ÷ Line 9, truncated to five decimal places
11 Schedule NG-HSG-1, page 2, line 16
12 Line 12 ÷ Line 12 column (a)
13 Schedule NG-HSG-1, page 2, line 28
14 Line 14 ÷ Line 14 column (a)
15 from Company forecast, including effect of proposed DSM programs
16 from page 2
17 Line 8
18 column (a) from page 2, line 8 for CY 2012; columns (b) - (g): column (a) x line (14)
19 column (a) from page 2, line 9 for CY 2012; columns (b) - (g): column (a) x line (12)
20 column (a) from page 2, line 10 for CY 2012; columns (b) - (g): column (a) x line (12)
21 Sum of Lines 17 through 20
22 Line 16 + Line 21
23 from page 3, line 7
24 Line 22 - Line 23

National Grid - Narragansett Electric Company
Illustrative Pension and Inspection & Maintenance Adjustment Factors

Line		CY 2011	CY 2012
PENSION ADJ			
1	Projected Pension Expense	$5,581,633	$6,581,633
2	Rate Year Pension Expense	$5,581,633	$5,581,633
3	Incremental	$0	$1,000,000
4	kWh Deliveries	7,874,058,477	8,106,768,760
5	Pension Adj	$0.00000	$0.00012
INSPECTION AND MAINTENANCE ADJ			
6	Projected I&M O&M Expense	$4,146,635	$4,146,635
7	Rate Year I&M O&M Expense	$4,146,635	$4,146,635
8	Incremental	$0	$0
9	kWh Deliveries	7,874,058,477	8,106,768,760
10	I&M Adj	$0.00000	$0.00000

Line Notes

1 Schedule NG-RLO-5, page 1 of 2
2 Schedule NG-RLO-5, page 1 of 2
3 Line 1 - Line 2
4 from page 3, line 16
5 Line 3 ÷ Line 4, truncated to five decimal places
6 NG-RLO-2, Page 24; rate year amount held constant for illustrative purposes only
7 Schedule NG-RLO-2, page, 24
8 Line 6 - Line 7
9 from page 4, line 13
10 Line 8 ÷ Line 9, truncated to five decimal places

National Grid - Narragansett Electric Company

Summary of Average Distribution Charges, by Rate Class for 2010, 2011 and 2012
Assuming All of Company Proposals are Approved by Commission Except the RDR Plan

Line		Company (a)	A-16/A-60 (b)	C-06 (c)	G-02 (d)	G-32/G-62 (e)	STL (f)	X-01 (g)
		Rates for CY 2010						
1	Revenue Requirement Docket 4065	$280,241,000	$150,507,000	$28,473,000	$40,255,000	$46,572,000	$14,107,000	$327,000
2	forecasted kWh deliveries for 2010	7,662,969,000	3,037,613,000	552,429,000	1,371,694,000	2,606,916,000	68,382,000	25,935,000
3	Average distribution charges effective 1/1/2010	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
4	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
5	Pension Adj.	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
6	Total Average distribution charge	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
		Rates for CY 2011						
7	Average distribution charges effective 1/1/2011	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
8	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
9	Pension Adj.	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
10	Total Average distribution charge	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
		Rates for CY 2012						
11	Average distribution charges effective 1/1/2012	$0.03657	$0.04955	$0.05154	$0.02935	$0.01786	$0.20630	$0.01261
12	Inspection and Maintenance Adj	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
13	Pension Adj.	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
14	Total Average distribution charge	$0.03669	$0.04967	$0.05166	$0.02947	$0.01798	$0.20642	$0.01273

Line Notes

1 from Schedule NG-HSG-1, page 2 of 50, line 22
2 from Schedule NG-HSG-2, page 2 of 35, line 1
3 Line 1 ÷ Line 2, rounded to five decimal places
4 n/a for 2010
5 n/a for 2010
6 sum of Lines 3 through 5
7 Line 3
8 from Attachment 1 to DIV 6-19(f) page 5 for 2011
9 from Attachment 1 to DIV 6-19(f) page 5 for 2011
10 sum of Lines 7 through 9
11 Line 7
12 from Attachment 1 to DIV 6-19(f) page 5 for 2012
13 from Attachment 1 to DIV 6-19(f) page 5 for 2012
14 sum of Lines 11 through 13

Division Data Request 6-24

Request:

Please provide the documents, data, assumptions and calculations upon which the Company relies to:

a. Assess the value to the Company of the mitigated risk that the proposed RDR would yield for each of the first five years of RDR implementation or for as many years as the Company has made such assessments;

b. Estimate the magnitude of rate relief and other quantifiable benefits that customers within each rate class can expect to experience in dollar terms and percentage terms as a direct result of implementation of the proposed RDR in each year of the first five years of RDR implementation.

c. Compute the dollar value of reduced kWh requirements for customers in each rate class for each DSM program already in place in RI for the each year of the past five years. Please include in the response to this request documentation of any and all efforts by the Company to account for the influences of other factors (e.g., changes in income, changes in employment levels, changes in the overall cost of delivered electric service, changes in inflation, etc.) on electricity use by customers in each rate class.

Response:

a. The Company has considered the effect of revenue decoupling and the entire RDR Plan on financial risk in the testimony of Paul Moul, the Company's cost of capital witness. As described in Dr. Tierney's prefiled direct testimony, the revenue decoupling element of the RDR Plan provides some amount of revenue stability to the Company, but if that single new element alone were adopted without the other proposed elements of the RDR Plan, the introduction of revenue decoupling would not allow for growth in the Company's revenues arising from increasing sales. Such growth in revenues has historically been an important source of funding for activities (such as working capital, and new investment in infrastructure) that support the Company's ability to meet both customer service requirements and shareholders' interests in achieving allowed rates of return without resorting to frequent requests to state regulators for rate increases. Other aspects of the Company's RDR Plan, including the Net Inflation and Net CapEx Adjustments, are designed to provide the Company with sufficient funding to make needed investment in aging infrastructure and maintain reliable operations. However, the net effect of these various offsetting factors on the Company's enterprise risk has not been assessed by either Dr. Tierney or the Company, although Mr. Moul has performed

Division Data Request 6-24 (cont.)

analyses to determine an appropriate cost of capital given the RDR Plan in this proceeding.

b. Neither the Company nor Dr. Tierney has performed any analyses to quantify all of the customer benefits that would be created by the Company's RDR Plan. However, the Company's RDR Plan can be anticipated to provide many important benefits to rate payers.

First, as addressed in Dr. Tierney's testimony, the Company's RDR Plan decouples its revenues from sales, and thereby eliminates disincentives to the implementation of various demand-side programs designed to help customers better manage and reduce their energy use and lower the total amount they spend on their overall electricity bills. As described in some detail in Dr. Tierney's testimony, many observers (including state regulators, federal energy officials, energy companies, regulatory consultants, and others) have concluded that the adoption of revenue decoupling can be critical to the successful and efficient adoption of cost-effective energy efficiency for the benefit of consumers. Revenue decoupling is one way to help align the utility's and customers' interests in increased energy efficiency and lower overall costs to provide electricity service. Such an alignment offers significant potential to lower the total cost of customer bills, particularly given that the potentially significant savings available to consumers by reducing the energy commodity portion of customers' bills, which is disproportionately greater than charges associated with distribution service.

Second, as explained more fully in Dr. Tierney's testimony, the Company's RDR Plan would successfully decouple the Company's revenues from its sales while still ensuring that the Company has sufficient revenues to ensure that it can maintain and improve the quality and reliability of its services for the benefit of its customers. Both the Net Inflation and Net CapEx Adjustments can help to offset the decline in revenues the Company would otherwise experience by adopting revenue decoupling at a fixed revenue requirement as established in a rate order. These revenues will be needed to help to ensure that the distribution company is able to attract sufficient capital at attractive rates to consumers so that the utility may undertake investments needed to replace, refurbish and maintain the company's distribution infrastructure. These adjustments are particularly important at present given the growing investment needs, as a result of aging infrastructure, and growing investment cost, due to significant inflation in the cost of equipment and construction materials. The Company's RDR Plan can also help to ensure that rates reflect over time the distribution company's ability to attract capital at a low a cost as possible.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-24 (cont.)

Lastly, the Company's RDR Plan can also support rate stability for customers by smoothing rate increases by gradually adjusting rates to reflect changes in costs as they are incurred over time. Absent such a Plan, new rates reflecting underlying changes in the cost of service could introduce rate increases in single large incremental jumps reflecting the effect of multiple years of cost increases.

c. Please see Attachment DIV 6-24(c)-1, which provides the estimated dollar value of reduced kWh requirements for customers for each DSM program already in place in Rhode Island for the period from 2004 through 2008. The program savings used in this analysis are the savings reported to the RIPUC and the Collaborative (which includes representation from the Division) summarizing program results in the year as reported in the Company's year-end reports.

   The savings reported in the Company's year-end reports incorporate all of the evaluation effects that were reflected during goal setting for that program year. Those evaluation factors include realization rates determined through program impact evaluations, adjustments for persistence, as well as like-measure spillover, as allowed by the Commission. The factors noted in this question, changes in income, changes in employment levels, changes in the overall cost of delivered electric service, changes in inflation, etc. are not explicitly accounted for as part of the program evaluation effort.

Prepared by or under the supervision of: Susan F. Tierney

The Narragansett Electric Company d/b/a National Grid
Estimated Annual Lost Distribution Revenue

	2004 Estimated Lost Distribution Revenue (a)	2005 Estimated Lost Distribution Revenue (b)	2006 Estimated Lost Distribution Revenue (c)	2007 Estimated Lost Distribution Revenue (d)	2008 Estimated Lost Distribution Revenue (e)
Large Commercial/Industrial					
Design 2000plus	$168,020	$144,264	$118,149	$167,729	$192,056
Energy Initiative	$244,206	$266,069	$418,579	$284,915	$281,731
SUBTOTAL	**$412,226**	**$410,333**	**$536,728**	**$452,644**	**$473,786**
Small Commercial/Industrial					
Small Business Services	$120,553	$169,733	$204,450	$190,676	$175,489
SUBTOTAL	**$120,553**	**$169,733**	**$204,450**	**$190,676**	**$175,489**
Residential Programs					
IN-HOME					
Appliance Management	$18,676	$36,757	$37,498	$43,343	$30,441
EnergyWise	$132,905	$102,137	$115,173	$118,577	$103,132
SUBTOTAL	$151,581	$138,894	$152,671	$161,920	$133,573
PRODUCTS					
Energy Star ® Products/Appliances	$48,576	$45,230	$49,589	$17,012	$17,298
Energy Star ® Lighting	$475,654	$782,649	$543,212	$604,157	$424,945
Energy Star ® Heating System	$464	$481	$330	$588	$2,826
Energy Star ® Central Air Conditioning	2,843	2,423	559	2,852	3,137
SUBTOTAL	$527,537	$830,784	$593,691	$624,609	$448,206
New Construction/Energy Star ® Home	$12,226	$22,078	$44,696	$33,987	$45,987
SUBTOTAL	**$691,344**	**$991,757**	**$791,057**	**$820,516**	**$627,766**
TOTAL	**$1,224,123**	**$1,571,823**	**$1,532,235**	**$1,463,836**	**$1,277,042**

(a) Page 2, Column (c)
(b) Page 3, Column (c)
(c) Page 4, Column (c)
(d) Page 5, Column (c)
(e) Page 6, Column (c)

The Narragansett Electric Company d/b/a National Grid
Estimated 2004 Annual Lost Distribution Revenue

	2004 kWh Savings (a)	Average Distribution Rate (b)	Estimated Lost Distribution Revenue (c)	Estimated Lost Distribution Revenue A-16	A-60	C-06/G-02	G-32
Large Commercial/Industrial							
Design 2000plus	11,260,961	$0.01492	$168,020				$168,020
Energy Initiative	16,367,119	$0.01492	$244,206				$244,206
SUBTOTAL	**27,628,080**		**$412,226**				**$412,226**
Small Commercial/Industrial							
Small Business Services	4,768,153	$0.02528	$120,553			$120,553	
SUBTOTAL	**4,768,153**		**$120,553**			**$120,553**	
Residential Programs							
IN-HOME							
Appliance Management Program							
(Low Income)/ Single Family							
Low Income Services	721,346	$0.02589	$18,676		$18,676		
EnergyWise	3,611,547	$0.03680	$132,905	$132,905			
SUBTOTAL	4,332,893		$151,581	$132,905	$18,676		
PRODUCTS							
Energy Star ® Products/Appliances	1,320,011	$0.03680	$48,576	$48,576			
Energy Star ® Lighting	12,925,382	$0.03680	$475,654	$475,654			
Energy Star ® Heating System	12,600	$0.03680	$464	$464			
Energy Star ® Central Air Conditioning	77,254	$0.03680	2,843	2,843			
SUBTOTAL	14,335,247		$527,537	$527,537			
New Construction/Energy Star ® Home	332,229	$0.03680	$12,226	$12,226			
SUBTOTAL	**19,000,369**		**$691,344**	**$672,668**	**$18,676**		
TOTAL	**51,396,602**		**$1,224,123**	**$672,668**	**$18,676**	**$120,553**	**$412,226**

(a) Page 7, Column (a)

(b) Average distribution rate for variable portion of distribution charges (does not reflect fixed customer charge). Rate G-32 used for Large C&I. A weighted average of Rates C-06 and G-02 used for Small C&I. Rate A-16 used for all Residential Programs except the Low Income Program, which reflects Rate A-60.

(c) Column (a) x Column (b)

The Narragansett Electric Company d/b/a National Grid
Estimated 2005 Annual Lost Distribution Revenue

	2005 kWh Savings (a)	Average Distribution Rate (b)	Estimated Lost Distribution Revenue (c)	Estimated Lost Distribution Revenue A-16	A-60	C-06/G-02	G-32
Large Commercial/Industrial							
Design 2000plus	10,166,618	$0.01419	$144,264				$144,264
Energy Initiative	18,750,454	$0.01419	$266,069				$266,069
SUBTOTAL	**28,917,072**		**$410,333**				**$410,333**
Small Commercial/Industrial							
Small Business Services	7,718,416	$0.02199	$169,733			$169,733	
SUBTOTAL	**7,718,416**		**$169,733**			**$169,733**	
Residential Programs							
IN-HOME							
Appliance Management Program							
(Low Income)/ Single Family							
Low Income Services	1,203,179	$0.03055	$36,757		$36,757		
EnergyWise	3,021,815	$0.03380	$102,137	$102,137			
SUBTOTAL	4,224,994		$138,894	$102,137	$36,757		
PRODUCTS							
Energy Star ® Products/Appliances	1,338,175	$0.03380	$45,230	$45,230			
Energy Star ® Lighting	23,155,300	$0.03380	$782,649	$782,649			
Energy Star ® Heating System	14,240	$0.03380	$481	$481			
Energy Star ® Central Air Conditioning	71,691	$0.03380	2,423	2,423			
SUBTOTAL	24,579,406		$830,784	$830,784			
New Construction/Energy Star ® Home	653,202	$0.03380	$22,078	$22,078			
SUBTOTAL	**29,457,602**		**$991,757**	**$955,000**	**$36,757**		
TOTAL	**66,093,090**		**$1,571,823**	**$955,000**	**$36,757**	**$169,733**	**$410,333**

(a) Page 7, Column (b)
(b) Average distribution rate for variable portion of distribution charges (does not reflect fixed customer charge). Rate G-32 used for Large C&I. A weighted average of Rates C-06 and G-02 used for Small C&I. Rate A-16 used for all Residential Programs except the Low Income Program, which reflects Rate A-60.
(c) Column (a) x Column (b)

The Narragansett Electric Company d/b/a National Grid
Estimated 2006 Annual Lost Distribution Revenue

	2006 kWh Savings (a)	Average Distribution Rate (b)	Estimated Lost Distribution Revenue (c)	Estimated Lost Distribution Revenue A-16	A-60	C-06/G-02	G-32
Large Commercial/Industrial							
Design 2000plus	8,326,250	$0.01419	$118,149				$118,149
Energy Initiative	29,498,150	$0.01419	$418,579				$418,579
SUBTOTAL	**37,824,400**		**$536,728**				**$536,728**
Small Commercial/Industrial							
Small Business Services	9,297,160	$0.02199	$204,450			$204,450	
SUBTOTAL	**9,297,160**		**$204,450**			**$204,450**	
Residential Programs							
IN-HOME							
Appliance Management Program (Low Income)/ Single Family							
Low Income Services	1,227,430	$0.03055	$37,498		$37,498		
EnergyWise	3,408,480	$0.03379	$115,173	$115,173			
SUBTOTAL	4,635,910		$152,671	$115,173	$37,498		
PRODUCTS							
Energy Star ® Products/Appliances	1,467,570	$0.03379	$49,589	$49,589			
Energy Star ® Lighting	16,076,130	$0.03379	$543,212	$543,212			
Energy Star ® Heating System	9,780	$0.03379	$330	$330			
Energy Star ® Central Air Conditioning	16,530	$0.03379	559	559			
SUBTOTAL	17,570,010		$593,691	$593,691			
New Construction/Energy Star ® Home	1,322,750	$0.03379	$44,696	$44,696			
SUBTOTAL	**23,528,670**		**$791,057**	**$753,559**	**$37,498**		
TOTAL	**70,650,230**		**$1,532,235**	**$753,559**	**$37,498**	**$204,450**	**$536,728**

(a) Page 7, Column (c)
(b) Average distribution rate for variable portion of distribution charges (does not reflect fixed customer charge). Rate G-32 used for Large C&I. A weighted average of Rates C-06 and G-02 used for Small C&I. Rate A-16 used for all Residential Programs except the Low Income Program, which reflects Rate A-60.
(c) Column (a) x Column (b)

The Narragansett Electric Company d/b/a National Grid
Estimated 2007 Annual Lost Distribution Revenue

	2007 kWh Savings (a)	Average Distribution Rate (b)	Estimated Lost Distribution Revenue (c)	Estimated Lost Distribution Revenue A-16	A-60	C-06/G-02	G-32
Large Commercial/Industrial							
Design 2000plus	11,820,200	$0.01419	$167,729				$167,729
Energy Initiative	20,078,600	$0.01419	$284,915				$284,915
SUBTOTAL	**31,898,800**		**$452,644**				**$452,644**
Small Commercial/Industrial							
Small Business Services	8,670,770	$0.02199	$190,676			$190,676	
SUBTOTAL	**8,670,770**		**$190,676**			**$190,676**	
Residential Programs							
IN-HOME							
Appliance Management Program (Low Income)/ Single Family							
Low Income Services	1,418,770	$0.03055	$43,343		$43,343		
EnergyWise	3,510,260	$0.03378	$118,577	$118,577			
SUBTOTAL	4,929,030		$161,920	$118,577	$43,343		
PRODUCTS							
Energy Star ® Products/Appliances	503,620	$0.03378	$17,012	$17,012			
Energy Star ® Lighting	17,885,040	$0.03378	$604,157	$604,157			
Energy Star ® Heating System	17,420	$0.03378	$588	$588			
Energy Star ® Central Air Conditioning	84,430	$0.03378	2,852	2,852			
SUBTOTAL	18,490,510		$624,609	$624,609			
New Construction/Energy Star ® Home	1,006,120	$0.03378	$33,987	$33,987			
SUBTOTAL	**24,425,660**		**$820,516**	**$777,173**	**$43,343**		
TOTAL	**64,995,230**		**$1,463,836**	**$777,173**	**$43,343**	**$190,676**	**$452,644**

(a) Page 7, Column (d)
(b) Average distribution rate for variable portion of distribution charges (does not reflect fixed customer charge). Rate G-32 used for Large C&I. A weighted average of Rates C-06 and G-02 used for Small C&I. Rate A-16 used for all Residential Programs except the Low Income Program, which reflects Rate A-60.
(c) Column (a) x Column (b)

The Narragansett Electric Company d/b/a National Grid
Estimated 2008 Annual Lost Distribution Revenue

	2008 kWh Savings (a)	Average Distribution Rate (b)	Estimated Lost Distribution Revenue (c)	Estimated Lost Distribution Revenue A-16	A-60	C-06/G-02	G-32
Large Commercial/Industrial							
Design 2000plus	13,534,580	$0.01419	$192,056				$192,056
Energy Initiative	19,854,170	$0.01419	$281,731				$281,731
SUBTOTAL	**33,388,750**		**$473,786**				**$473,786**
Small Commercial/Industrial							
Small Business Services	7,980,170	$0.02199	$175,489			$175,489	
SUBTOTAL	**7,980,170**		**$175,489**			**$175,489**	
Residential Programs							
IN-HOME							
Appliance Management Program (Low Income)/ Single Family							
Low Income Services	996,440	$0.03055	$30,441		$30,441		
EnergyWise	3,053,960	$0.03377	$103,132	$103,132			
SUBTOTAL	4,050,400		$133,573	$103,132	$30,441		
PRODUCTS							
Energy Star ® Products/Appliances	512,220	$0.03377	$17,298	$17,298			
Energy Star ® Lighting	12,583,510	$0.03377	$424,945	$424,945			
Energy Star ® Heating System	83,680	$0.03377	$2,826	$2,826			
Energy Star ® Central Air Conditioning	92,900	$0.03377	3,137	3,137			
SUBTOTAL	13,272,310		$448,206	$448,206			
New Construction/Energy Star ® Home	1,361,770	$0.03377	$45,987	$45,987			
SUBTOTAL	**18,684,480**		**$627,766**	**$597,325**	**$30,441**		
TOTAL	**60,053,400**		**$1,277,042**	**$597,325**	**$30,441**	**$175,489**	**$473,786**

(a) Page 7, Column (e)
(b) Average distribution rate for variable portion of distribution charges (does not reflect fixed customer charge). Rate G-32 used for Large C&I. A weighted average of Rates C-06 and G-02 used for Small C&I. Rate A-16 used for all Residential Programs except the Low Income Program, which reflects Rate A-60.
(c) Column (a) x Column (b)

The Narragansett Electric Company d/b/a National Grid

Energy Savings (Annual MWh Savings) Per Year by Program

Program	**2004**	**2005**	**2006**	**2007**	**2008**	**Total**
Large Commercial and Industrial	**(a)**	**(b)**	**(c)**	**(d)**	**(e)**	
Design 2000*plus*	11,261	10,167	8,326	11,820	13,535	55,109
Energy Initiative	16,367	18,750	29,498	20,079	19,854	104,548
Small Commercial and Industrial						
Small Business Services	4,768	7,718	9,297	8,671	7,980	38,435
Residential						
Appliance Management Program (Low Income)/ Single Family Low Income	721	1,203	1,227	1,419	996	5,567
Energy*Wise*	3,612	3,022	3,408	3,510	3,054	16,606
Energy Star ® Products/Appliances	1,320	1,338	1,468	504	512	5,142
Energy Star ® Lighting	12,925	23,155	16,076	17,885	12,584	82,625
Energy Star ® Heating System	13	14	10	17	84	138
Energy Star ® Central Air Conditioning	77	72	17	84	93	343
New Construction/Energy Star ® Home	332	653	1,323	1,006	1,362	4,676
Home Energy Managemen	n/a	n/a	n/a	n/a	n/a	n/a
Total	51,397	66,093	70,650	64,995	60,053	313,189

Notes:

1) New Construction renamed to Energy Star ® Homes, 2006
2) Energy Star ® Products renamed to Energy Star ® Appliances, 2006
3) Information and Education renamed Energy Efficiency Education Programs, 2006
4) Appliance Management Program (Low Income) renamed Single Family Low Income Services, 2006

Sources:

(a) Revised 2004 DSM Year-End Report for The Narragansett Electric Company - Table 1. Summary of 2004 Target and Year-End Results Column (7)
(b) Revised 2005 DSM Year-End Report for The Narragansett Electric Company - Table 1. Summary of 2005 Target and Year-End Results Column (7)
(c) National Grid Demand-Side Management Programs, Electric Operations 2006 Year-End Report - Table 1. Summary of 2006 Target and Year-End Results Column (7)
(d) National Grid Demand-Side Management Programs, Electric Operations 2007 Year-End Report - Table 1. Summary of 2007 Target and Year-End Results Column (7)
(e) National Grid Electric and Gas Demand-Side Management Programs, Electric Operations 2008 Year-End Report - Table E1. Summary of 2087 Target and Year-End Results Column (7)

Division Data Request 6-25

Request:

Please provide the documents, data, assumptions and calculations upon which the Company relies to estimate the forecasted savings in terms of reductions in delivered kWh for each rate class in each of the next five years for each DSM program addressed in the testimony of witness Stout.

Response:

The Company has not prepared an estimate of forecasted savings for a five-year period for each rate class for each program either internally or for any prior filing before the Commission. However, the Company has prepared a forecast of savings by program for calendar year 2009 and a forecast of aggregated savings in years 2010 – 2011. Projected savings by program in 2009 were provided by the Company in its Energy Efficiency Program Plan for 2009 and approved by the Commission on December 23, 2008 (Docket No. RIPUC 4000). Aggregated savings projections were submitted to the Commission in the Company's three-year Least Cost Procurement Plan filed in Docket No. RIPUC 3931 and were approved by the Commission on March 31, 2009.

Attachment DIV 6-25-1 provides the aggregated savings projections approved by the Commission in RIPUC 3931. Attachment DIV 6-25-2 provides program-level savings projections as approved by the Commission in Docket RIPUC 4000, and reflects the extent to which savings are projected for different customer groupings (e.g., low-income residential, non-low-income residential).

The programs described on pages 157-160 of Mr. Stout's testimony are presented as examples of what the Company's programs will look like in the first year of the three-year Least Cost Procurement Plan, as detailed in the Energy Efficiency Program Plan for 2009 (Docket 4000).

The Company has not developed program designs beyond 2009.

Prepared by or under the supervision of: Timothy Stout

Table 1

2009-2011 Energy Efficiency Procurement Plan: Summary of Benefit, Costs, Savings ($000)

	2008	2009	2010	2011	3 Year Total
NPV Net Benefits ($000)	$60,341	$78,278	$93,458	$109,866	$281,602
NPV Utility Costs ($000)	$14,861	$24,430	$34,739	$43,296	$102,4661
TRC Benefit / Cost	4.00	3.22	2.95	2.83	2.97
Annual Energy Savings (MWh)	54,268	74,387	88,546	102,566	265,499
Annual kW	9,154	12,555	15,154	17,815	45,524
Lifetime MWh	636,784	893,011	1,084,987	1,272,891	3,250,888
Cost / Lifetime kWh	$ 0.032	$ 0.039	$ 0.044	$ 0.047	$ 0.044

Notes: Net benefits = benefits - (participant costs + utility costs - shareholder incentive)
Utility costs exclude shareholder incentive
TRC Benefit/Cost includes shareholder incentive as a cost

Div 6-25
Attachment 2

Table E-6
Comparison of Goals to Prior Year

	Proposed 2009		2008		Difference	
	Annual Energy Savings (MWh) (1)	Participants	Annual Energy Savings (MWh) (1)	Participants	Annual Energy Savings (MWh)	Participants
Program						
Commercial & Industrial						
Design 2000*plus*	10,423	239	9,157	159	1,267	80
Energy Initiative	28,808	245	21,039	145	7,769	100
Small and Medium Business	11,030	835	8,698	542	2,332	293
SUBTOTAL	**50,261**	**1,319**	**38,894**	**846**	**11,367**	**473**
Low Income Residential						
Single Family - Low Income Services	1,340	1,439	945	806	395	633
SUBTOTAL	**1,340**	**1,439**	**945**	**806**	**395**	**633**
Non-Low Income Residential						
ENERGY STAR® Homes	648	380	534	335	114	45
ENERGY STAR® Central Air Conditioning Program	93	546	116	620	(23)	(74)
ENERGY STAR® Heating	83	250	50	423	33	(173)
Energy*Wise*	4,392	6,194	1,875	2,962	2,517	3,232
ENERGY STAR® Lighting	18,074	68,548	11,974	51,650	6,100	16,898
ENERGY STAR® Appliances	4,439	7,600	415	3,750	4,024	3,850
SUBTOTAL	**27,729**	**83,518**	**14,964**	**59,740**	**12,766**	**23,778**
TOTAL	**79,331**	**86,276**	**54,803**	**61,392**	**24,528**	**24,883**

(1) Net Savings for 2008 calculated under "Rhode Island Benefit/Cost Test"; Net savings for 2009 calculated under Total Resource Cost Test.

Division Data Request 6-30

Request:

Re: page 94, line 19, through page 95, line 20 of witness Tierney's testimony please:

a. Explain the purpose of notifying the Commission when the difference between the actual target revenue (ATR) and actual revenue collected is greater then 10% and the action(s), if any, that the Company believes the Commission should take when such notification is received;

b. Provide the expected maximum level of the RDR Adjustment Factor that could result from the proposed RDM for each rate class stated as a percentage of the Company's proposed base rate charges (in average cents per kWh terms) for each class;

c. Provide the data, analyses and assumptions upon which the Company relies to demonstrate the reasonableness and appropriateness of the absence of an adjustment in the proposed RDM for differences between (i) the actual number of customers in each rate class for the period upon which base rates are set and (ii) actual numbers of customers during a subsequent annual period;

d. Provide quantitative examples to demonstrate how costs of new customer additions can be expected to vary by rate class.

Response:

a. As stated in the Dr. Tierney's prefiled Direct Testimony, under its RDR Plan the Company would notify the Commission if, at any point during the year, (1) the difference between the year-to-date actual revenue and the year-to-date Annual Target Revenue ("ATR') were 10 percent above or below the actual ATR, and (2) the Company did not anticipate that the discrepancy would fall below the 10 percent threshold in the remaining months of that RDR Plan year. The proposed RDR Plan also anticipates that as a part of this notification, the Company could also request that an interim rate adjustment be approved by the Commission prior to its next scheduled January 1st RDR Plan rate adjustments. Having received this notification from the Company, including supplemental information on year-to-date actual revenues and ATR, the Commission could make a determination as to whether an interim adjustment would be appropriate and, if so, the level of such an interim adjustment. Having the option to request an interim adjustment in the event of significantly higher- or lower-than-anticipated revenue collections could help to smooth any rate adjustments that would otherwise need to be made at the end of the year as a consequence of the over- or under-collection of billed

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-30 (cont.)

revenues. Notification by the Company would also provide its customers with information that could be helpful in helping them manage their energy use decisions in light of changes in customer rates.

b. The future level of the Company's RDR Adjustment Factor is uncertain. On the one hand, the dollar amount (and therefore percentage impact) of future Adjustment Factors in any year will depend directly or indirectly on a large number of factors that affects revenues relative to test-year levels. These factors include but are not limited to weather conditions, population levels, business activity, customers' purchase of electricity-using equipment, customer sales, the effectiveness and extent of customers' efforts to reduce energy use, the effects of other changes in economic conditions, general inflation, capital expenditures, construction and equipment costs, the rate and extent of infrastructure aging, and unanticipated events affecting infrastructure operating condition. In light of these many uncertainties, it is difficult to determine a maximum level to which the RDR Adjustment Factor might rise or fall in the future. For example, it is possible to imagine combinations of factors (e.g., aggressive adoption of energy efficiency combined with more extreme seasonal weather conditions, increased penetration of electronic and other electricity-using equipment, relatively low amounts of capital investment, etc.) that could lead to an over-collection of revenues relative to the ATR, which would lead to a reduction in rates. Similarly, it is possible to imagine a combination of events that could lead to an overall revenue reconciliation that would result in a positive RDR Adjustment Factor. To provide context, the anticipated level of RDR Adjustment Factor would rise to 0.164 cents in 2012, based on the illustrative calculations provided in Schedule NG-RLO-7.

c. While the Company's RDR Plan does not directly adjust for changes in the number of customers, the Company did not think it necessary to include such an explicit adjustment for the number of customers served because the Net Inflation and Net CapEx Adjustments included in its proposal together contribute to an overall revenue reconciliation mechanism sufficient to account for the revenue implications of potential changes in the number of customers served. Also, all billed revenues from new customers will be included in the Company's total billed revenues for the purposes of calculating the Annual Target Revenue reconciliation.

Rate adjustments to align a utility's revenues with changes in its underlying revenue requirements can be accomplished through a variety of mechanisms, including: revenue adjustment mechanisms tied explicitly to an allowed level of revenues per customer; net inflation adjustments; capital adjustment mechanisms; and adjustment of rates for costs that are beyond the utility's control and vary unpredictably (e.g., adjustments for fuel or pensions); partial decoupling; and other approaches. Ratemaking practices to decouple a

Division Data Request 6-30 (cont.)

company's revenues from its sales do not dictate a standard design reflecting a particular set of mechanisms and a particular design of and interaction between these mechanisms. Instead, the most appropriate design for a given utility will depend on various features of the specific utility's operating circumstances.[1]

The Company has developed an RDR Plan that includes both revenue decoupling as well as other mechanisms, such as the Net Inflation Adjustment and Net CapEx Adjustments, because the Company believes that this combination will provide benefits to both consumers and the Company. This package provides a more effective means of adjusting the Company's rates to align revenues with changes in factors affecting its underlying costs; thus, this package reflects underlying cost of service principles, while still effectively decoupling the Company's revenues from the level of its sales.

d. The information request asks for "quantitative examples to demonstrate how costs of new customer additions can be expected to vary by rate class." In order to provide such examples, it would first be necessary to establish certain assumptions (e.g., type of customers, characteristics of old and new customers' electricity use, elements of the utility's ratemaking structure) that would be applied in developing the example. The costs of new customers can vary across a wide range of factors. A preliminary list of such factors included the type of customer, customer size and energy use, customer geographic location, interconnection requirements, and customer services utilized (e.g., type of metering, type of pricing, voltage requirements, and station power.)

[1] For example, in its Decoupling Order, the Massachusetts Department Public Utilities provided both direct guidance on specific elements of decoupling approaches (such as full decoupling) to be used by investor-owned distribution companies in Massachusetts, as well as guidance on areas in which a utility may exercise discretion in the design of its proposed decoupling mechanisms. The latter occurred because the Department recognized that the most appropriate design for a given utility may depend on specific utility's operating circumstance. Specifically, it stated that: "Instead, we will consider company-specific ratemaking proposals that account for: (1) the impact of capital spending on a company's required revenue target; and (2) the inflationary pressures with respect to the prices of goods and services used by distribution companies. We recognize that circumstances will vary from company to company and, as such, we will permit a certain amount of flexibility when establishing a revenue requirement for a distribution company." Massachusetts Department of Public Utilities, Order, Massachusetts DPU Docket 07-50-A, July 16 2008, page 50.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-31

Request:

Re: Schedules NG-SFT-4 and NG-SFT-5, please:

a. Provide the analyses and rationales upon which National Grid would rely to demonstrate to this Commission that the productivity offsets estimated in the referenced schedules for past periods are reasonably indicative of the levels of productivity offsets that this Commission should expect in future periods for National Grid's Rhode Island operations;

b. Provide the analyses upon which the Company relies to determine that it is reasonable to set a productivity offset factor at a fixed level that does not vary over time or with changing economic conditions, changing utility operations, or changes in factors within managements control;

c. Provide the witness' understanding of impact that utility acquisitions and mergers and utility industry restructuring have had on distribution utility productivity over the past 10-15 years;

d. Provide the data, studies and analyses the witness relies upon to support her understanding of the manner in which the influences of utility acquisitions and mergers and utility industry restructuring were addressed in the development of the estimates of energy distribution productivity that are presented in the referenced schedules;

e. Provide the Company's best estimate of the expected dollar value of the proposed 0.5% productivity offset at the time that the first annual Net Inflation Adjustment would be computed under the provisions of the Company's RDM;

f. Indicate when and in what forum the Company would propose that the on-going appropriateness of the initial 0.5% productivity offset factor would be reviewed by the Commission.

Response:

a. In each year after the new rates would go into effect, the Company's proposed Net Inflation adjustment would be based on changes in an economy-wide price index and a fixed productivity offset factor. As described in Dr. Tierney's prefiled direct testimony, the Company has proposed to use a productivity offset factor of 0.5 percent based on the results of recent studies of distribution company productivity. Many factors potentially

Division Data Request 6-31 (cont.)

affect the level of the productivity offset over time, although these factors do not suggest that this factor should be increasing or decreasing over time.

Based on indexing theory construct commonly used to develop inflation adjustments in the context of the electric power sector, the productivity offset depends on four economic measures, including distribution company productivity.[1] All of these measures can change due to a variety of economic circumstances. For example, with regard to the distribution company productivity, opportunities to reduce costs may decline over time as companies act on cost-reducing opportunities starting with those that are the easiest to identify and provide the greatest benefit (i.e., the "low hanging fruit"). However, new technologies may become available over time to create new opportunities to increase efficiency and lower costs. Certain new technologies, such as particular aspects of the suite of "Smart Grid" technologies, potentially offer such opportunities for distribution companies and other segments of the electric power industry. Market and regulatory conditions can also affect realizable and realized productivity gains, particularly when financial incentives are introduced that allow firms to capture more the financial benefits of productivity improvements (e.g., as with performance-based regulation.) Thus, in principle, distribution company productivity could increase or decrease over time.

b. Certain studies analyzed by Dr. Tierney as a part of the research undertaken in developing her prefiled expert testimony provide some information on recent trends in distribution company productivity. In general, these studies suggest that annual changes in distribution company productivity have been decreasing over time, although they do not elaborate on the factors driving such productivity improvements over time. For example, one study estimates that electric distribution productivity improvements for utilities in Northeast states were 0.75 percent annually when measured over the period 1996 to 2006, whereas it was 0.58 percent when measured over the period 2001 to 2006.[2] Another study found that nationwide electric distribution productivity improvements were 0.7 percent annually when measured over the period 1994 to 2004, but 0.1 percent when measured over the more recent period 1998 to 2004.[3] While these figures suggest that opportunities for productivity increases may be declining over time, caution should be exercised in drawing conclusions about trends in power distribution productivity over time given the variability in annual productivity data and the resulting sensitivity of average productivity values to the choice of estimation period.

[1] As described in footnote 65 of Dr. Tierney's prefiled direct testimony, the other economic measures are economy-wide total factor productivity, distribution company prices, and economy-wide input prices.
[2] Mark Lowry, et al., Revenue Adjustment Mechanisms for CVPS, June 23, 2008, on behalf of Central Vermont Public Service Company, Vermont Public Service Board, Docket No. 7336, Exhibit CVPS-Rebuttal-MNL-2.
[3] Robert Camfield, Direct Testimony, State Corporation Commission of Kansas, on behalf of Kansas City Power & Light Company, Docket No. 06-KCPE-828-RTS.

Division Data Request 6-31 (cont.)

Empirical estimates of annual changes in productivity vary from year to year, particularly when measured for narrow industry segments, such as electric power distribution. Thus, a Net Inflation adjustment that utilized a productivity offset factor that varied from year-to-year based on annual changes in productivity would introduce variability into customer rates without necessarily adding precision to productivity offset estimates. For this reason, in almost all cases, performance based rate plans that have relied upon inflation adjustments such as that proposed in the Company's Net Inflation adjustment rely upon productivity measures that are both fixed and based upon empirical estimates of productivity improvements as measured over multiple years.

The Company's proposal is also designed to provide a mechanism in which the quantitative parameters used are grounded in transparent and reliable empirical measures. However, Dr. Tierney is unaware of any reliable empirical assessments of the impact the certain features of the Company's business or operating environment (e.g., economic conditions, utility operations or management controls) on its productivity. Absent such empirical studies, it might be unduly speculative to introduce such factors into the Net Inflation adjustment.

c. Mergers and acquisitions within the utility sector offer the opportunity for productivity gains in various operations by, for example, accessing increased economies of scale, reducing transaction and contracting costs, reducing information asymmetries, and providing opportunities for synergies in offerings and services. While offering these illustrations of factors that affect productivity gains, neither Dr. Tierney nor National Grid have not performed any research to determine, in actuality, whether and to what extent such efficiencies have been realized

d. None of the studies assessed by Dr. Tierney includes an explicit discussion of how any merger and acquisition activity was accounted for in their analyses. Based on her review, she found generally that these studies used sound methodological approaches and are based upon reliable data, which gave her no reason to believe that merger and acquisition activity was not properly treated in these studies.

e. The Company will supplement this response as soon as it is available.

f. Under the Company's RDR Plan, the 0.5% productivity offset factor would remain in effect until the Company filed its next full rate case for an adjustment to base rates. At that time, a review of the productivity offset could be undertaken to determine whether any modification to the 0.5% value were needed to develop an indexing mechanism that appropriately allowed the Company to recover revenues to match changes in cost trends affecting operations and maintenance costs.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-34

Request:

Re: Schedule HSG-11, R.I.P.U.C. No. 2017, Sheet 2, Section II.A., please:

a. Provide the data, analyses, and assumptions upon which the Company relies to assess the reasonableness, appropriateness of using the Gross Domestic Product Price Index (GDP-PI) as the measure of inflation experienced by the Company's Rhode Island electric operations. As part of the response to this request, please identify each alternative inflation index that the Company considered and provide the data, analyses and assumptions used it the Company's evaluation of each alternative index.

b. Explain why an inflation index tailored more specifically to Rhode Island, New England, or the Northeastern U.S. would not be a more appropriate basis for computing an inflation adjustment.

c. Provide the data, analyses, and assumptions upon which the Company relies to assess the reasonableness, appropriateness of using the allocator for "overall O&M" determined its distribution rate case to compute the portion of the Net Inflation Adjustment amount to be used in the computation of the per kilowatt-hour factor for each rate class.

d. Indicate whether the Company intends to reconcile Net Inflation Adjustment revenue collections on a class-by-class basis, and if not, please explain what is accomplished by allocating the Net Inflation Adjustment to rate classes and applying rate class specific cents per kilowatt-hour adjustment factors.

e. Provide a full itemization of the components of the referenced $148,570,000 amount of Net Operating Expense Subject to Inflation.

f. Indicate how and when the Company intends to reconcile its inflation and productivity adjusted annual O&M costs with its actual O&M costs.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-34 (cont.)

Response:

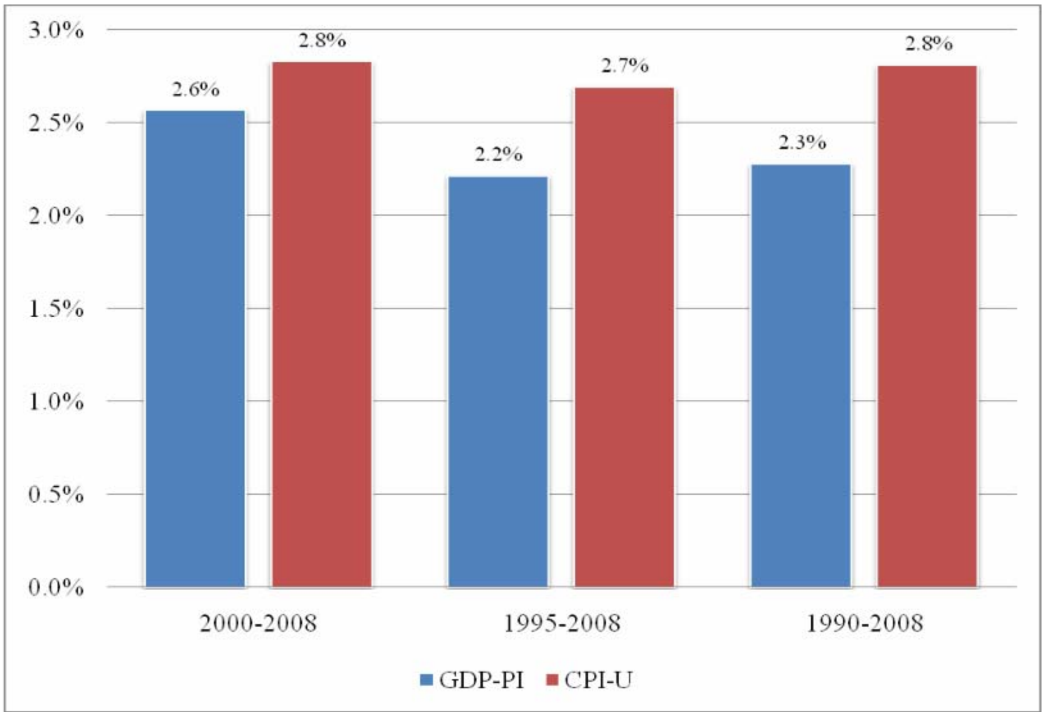
a. As discussed in Dr. Tierney's prefiled expert testimony, a number of factors were considered in the selection of an appropriate measure of inflation to use in the Company's Net Inflation adjustment. The Gross Domestic Product Price Index ("GDP-PI") was selected because of a number of advantages.[1] The GDP-PI is one of the prime measures of economy-wide price inflation. By some accounts, the GDP-PI is more accurate and reliable than alternative measures of economy-wide inflation, such as the consumer price index.[2] The GDP-PI is also available in a timely fashion.

   The GDP-PI is also commonly chosen as the measure of cost inflation in various inflation indexing mechanisms, such as those used in performance-based rate plans. For example, of the five inflation indexing mechanisms represented in Schedule NG-SFT-4 of Dr. Tierney's prefiled direct testimony, four of them use the GDP-PI. Of those she studied, the only indexing mechanism not to propose the GDP-PI is one study that instead chose to propose the use of the Consumer Price Index for all urban consumers ("CPI-U").[3] For comparison purposes, Figure Div 6-34, below, reports the average annual growth rate in the GDP-PI and CPI-U, as measured over different time periods. The figure shows that inflation, as measured by the GDP-PI, has been lower than when measured by the CPI-U.

[1] Note that the GDP-PU is measured by the U.S. Department of Commerce's Bureau of Economic Analysis, not the Bureau of Labor Statistics, as reported in Dr. Tierney's prefiled expert testimony.
[2] For example, see Lawrence Kaufmann, Direct Testimony, Concerning Performance-Based Regulation, on behalf of Bay State Gas Company, Massachusetts Department of Telecommunications and Energy, Docket 05-27, Exhibit BSG/LRK-1.
[3] Boston Gas Company, Bay State Gas Company, Central Maine Power and NStar all proposed and were approved for rate plans using the GDP-PI. Central Vermont Public Service approved a rate plan using the CPI-U, although this plan was not approved.

Division Data Request 6-34 (cont.)

Figure Div 6-34
Alternative Measures of Economy-wide Inflation:
Gross Domestic Product Price Index (GDP-PI) and
Consumer Price Index for Urban Consumers (CPI-U)



b. There are several reasons why the Company is not proposing to use a regional measure of cost inflation instead of the GDP-PI. First, the Bureau of Economic Analysis does not measure GDP-PI at the regional or state level. Second, using a state or regional measure of cost inflation would require significant additional analysis to develop an estimate the productivity offset that corresponds to the same geographic region. As described in Dr. Tierney's prefiled expert testimony, the net inflation factor in each year will be based on the following formula:

$$I = \frac{GDPPI_Y}{GDPPI_{Y-1}} - P - 1$$

In this formula, the productivity offset, *P*, and the inflation measure, in this case *GDP-PI*, must be measured over the same geographic regions to provide a reliable index for

Division Data Request 6-34 (cont.)

adjusting the Company's operations and maintenance costs. If a regional- or state-specific measure of inflation were used, then the productivity estimate would need to be re-estimated to reflect the total factor productivity of the regional- or state-level economies and the change in input prices at the regional- or state-level. The approach used by Dr. Tierney to develop the proposed productivity offset relied upon a review of results and estimates of productivity estimates from multiple recent studies. For those studies estimating a productivity offset, all estimated the productivity offset at the national level. For these many reasons, the use of a state or regional measure of inflation was not further explored by the Company.

c. The Company's proposed Net Inflation adjustment would provide a change in revenue requirements to reflect changes in the costs of goods and services used in providing services for its customers. Because this adjustment would only reflect changes in the costs of operations and maintenance, it is appropriate to allocate these costs to customers in the same manner approved by the Commission for the allocation of test year revenue requirement to different rate classes – that is, using the final allocators for operations and maintenance costs. Such an allocation would be consistent with the ratemaking approach that attempts to assign costs to customers based on the level of costs they impose on the utility. As described in the Company's response to the Division's information request 6-2, such an approach has important efficiency and equity benefits.

d. The Company intends to allocate revenue requirements associated with the Net Inflation adjustments on a class-by-class basis. Under this approach, Net Inflation rate adjustments will be set to recover each class' portion of the total revenue requirement for the adjustment as determined by the test year allocators for operations and maintenance costs. Rates will be set by dividing this class-specific revenue requirement by the class' forecast billing determinants for the upcoming year.

e. As shown on Schedule NG-RLO-7, Page 2, Line 5, the amounts subject to the Net Inflation Adjustment include the Company's total operating expenses of $218,758,717, less the following items:

- Pension / OPEB Expense
- Commodity Costs Tracker
- Loss on Reacquired Debt
- Depreciation
- Economic Development Program
- Net Synergy Expense Adjustments
- Environmental and Storm Fund Collections
- Inspection & Maintenance Program.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-34 (cont.)

Following these adjustments, the amount subject to the Net Inflation Adjustment equals $142,628,068, as shown on Schedule NG-RLO-7, Page 2, Line 16. Attachment DIV 6-34(e) provides a reconciliation of amounts included the Company's cost of service on Schedule NG-RLO-2, Page 1 to amounts included on Schedule NG-RLO-7, Page 2.

It should be noted that the amount subject to the Net Inflation Adjustment referenced in the proposed tariff included in Schedule NG-HSG-11 ($148,570,000) was a preliminary amount that was inadvertently not updated with information in Schedule NG-RLO-7, Page 2, Line 16. For ease of reference, the Company is providing Schedule NG-RLO-7 as Attachment 2 to DIV 6-34(e).

It should also be noted that both Schedule NG-RLO-7 and the amount appearing in the proposed tariff included in Schedule NG-HSG-11 are illustrative and will be replaced with final amounts upon approval by the Commission of the Company's decoupling proposal.

f. Each RDR Plan filing, made in November 1 of each year, will include a calculated Net Inflation adjustment that will reflect (1) test-year operations and maintenance costs, and (2) the actual percentage change in the GDP-PI between the current year and the prior year. In this calculation, the current year is calculated as the average of the prior four quarterly measures of the GDP-PI as of the second quarter of each year. For example, the Net Inflation adjustment for 2011 will reflect the percent change in GDP-PI from 2009 (as measured by the average GDP-PI from the last two quarters of 2008 and the first two quarters of 2009) to 2010 (as measured by the average GDP-PI from the last two quarters of 2009 and the first two quarters of 2010). Because this adjustment is based solely upon actual data available at the time of the November 1 filing, there is no need to reconcile this adjustment in subsequent years. Under this mechanism, the Company assumes the risk of controlling its O&M costs at a level equal to the Net Inflation adjustment. There is no subsequent adjustment in rates to reconcile the Company's the Net Inflation adjustment with its actual O&M costs, regardless of whether actual O&M costs in any year are greater or less than the amount allowed in the Annual Target Revenue for that year.

Prepared by or under the supervision of: Susan F. Tierney

Narragansett Electric Company d/b/a National Grid
Reconciliation of Operating Expenses
COS Schedule (NG-RLO-2) to Decoupling Schedule (NG-RLO-7)

Line			(a) NG-RLO-2 Column (h)	(b) NG-RLO-7 Column (A), Line 5
	Operating Expenses:			
1	Purchased Power		$ 37,947	$ 37,947
2	Transmission O&M - Wheeling Costs - NEP		-	-
3	Transmission O&M - Integrated Facilities Agreement		-	-
4	Energy Efficiency O&M		-	-
5	Other Operation & Maintenance Expenses		137,113,118	137,113,118
6	Uncollectible Expense		5,020,447	5,020,447
7	Commodity Cost Tracker		9,751,787	9,751,787
8	Donations		548,593	548,593
9	Pension and OPEB cost Recovery (R.I.P.U.C. Dkt No. 3617)		2,511,132	-
10	Environmental Response Fund		3,078,000	-
11	Merger Related Cost to Achieve		2,100,000	-
12	Depreciation		41,465,676	41,465,676
13	Municipal Tax		20,085,331	20,085,331
14	Payroll Tax		3,699,741	3,699,741
15	Other Taxes		274,629	274,629
16	Remove Commodity Cost Tracker		(9,751,787)	-
17	Gross Receipts Tax (GRT)		-	-
18	Amortization of Investment Tax Credit		-	-
19	Amortization of Loss on Reacquired Debt		686,219	686,219
20	Interest on Customer Deposits		75,229	75,229
21	Estimated NGRID/KeySpan Transaction Synergies		(6,200,000)	-
22	Company Share of Net Synergies		3,250,000	-
23	Federal & Deferred Income Tax		18,999,287	-
24				
25	Total Operating Expenses per NG-RLO-2, Line 35 and NG-RLO-7, Line 5		$ 232,745,348	$ 218,758,716
26				
27	Less Amounts Included Above Not Subject to Inflation:			
28				
29	Pension / OPEB Expense subject to Regulatory Reconciliation	/1	(13,581,795)	(13,581,795)
30	Pension / OPEB Expense recovered per Docket No. 3617 per above		(2,511,132)	-
31	Loss on Reacquired Debt per above		(686,219)	(686,219)
32	Depreciation per above		(41,465,676)	(41,465,676)
33	Economic Development Program	/2	(1,000,000)	(1,000,000)
34	Environmental and Storm Fund Collections		(4,119,000)	(4,119,000)
35	Inspection & Maintenance Program	/2	(4,676,172)	(4,676,172)
36	Commodity Cost Tracker		-	(9,751,787)
37	Net Synergy Expense Adjustments per above	/3	-	(850,000)
38	Federal & Deferred Income Tax per above		(18,999,287)	-
39	Environmental Response Fund per above	/4	(3,078,000)	-
40				
41	Total per NG-RLO-7, Page 2, Line 16		$ 142,628,068	$ 142,628,068

/1 Amount is included on line 5 above and equals NG-RLO-2, Page 10, Line 34 + NG-RLO-2, Page 11, Line 19. Note: This amount should have been $14,243,640 per NG-RLO-5, Page 1, Line 10 + NG-RLO-5, Page 2, Line 10.

/2 Amounts are included on line 5 above.

/3 Amount equals the sum of lines 11, 21 and 22 above.

/4 Amount should have been included in Total Operating Expenses per NG-RLO-7, Page 2, Line 5.

Narragansett Electric Company
d/b/a National Grid
Docket No. ________
Exhibit -NG-RLO-7
Page 1 of 4

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of RDM Revenue Adjustments

Line		(A) CY 2010	(B) CY 2011	(C) CY 2012
	Calculation of Annual Target Revenue (ATR)			
1	Revenue Requirement Docket _______	281,076,526	281,076,526	281,076,526
2	Net Inflation Adjustment		1,697,274	4,136,372
3	Prior Year RDR Plan Revenue Reconciliation		0	2,752,724
4	Cumulative Net Historic Capital Adjustment	0	3,926,349	11,819,741
5	Annual Target Revenue	281,076,526	286,700,149	299,785,363
		Rates for CY 2010	**Rates for CY 2011**	**Rates for CY 2012**
	Components of Billed Revenue			
6	Revenue Requirement Docket _______	281,076,526	281,076,526	281,076,526
7	Prior Year RDR Plan Revenue Reconciliation		0	2,752,724
8	Net Inflation Adjustment		1,697,274	4,136,372
9	Cumulative Net Historic Capital Adjustment - Prior Year		0	3,926,349
10	Current Year Capital Adjustment		1,173,625	1,765,509
11	Cumulative RDR Plan Adjustment Factor Revenue	0	2,870,899	12,580,954
12	Total RDM Plan Revenue	281,076,526	283,947,425	293,657,480
13	Incremental RDR Plan Adjustment Factor Revenue	0	2,870,899	9,710,055
	Calculation of Annual RDM Reconciliation			
14	Actual Billed Revenue	281,076,526	283,947,425	293,657,480
15	Annual Target Revenue	281,076,526	286,700,149	299,785,363
16	Excess/(Under) billed Revenue	0	(2,752,724)	(6,127,883)

Line Notes

1 Distribution Revenue Requirement per Docket No. _____
2 From Page 2 of 4, Line 22
3 Prior year Line 16 x (-1)
4 From Page 3 of 4 Line 52 for Current Year
5 Sum of Lines 1 through 4
6 From Line 1
7 Prior year Line 15 x (-1) - Amount to be allocated over total forecasted kWh's
8 From Line 2 - Amount to be allocated to each class based on class O&M allocator
9 Prior Year Line 4 - Amount to be allocated to each class based on class rate base allocator
10 From Page 4 Line 37 for Current Year - Amount to be allocated to each class based on class rate base allocator
11 Sum of Lines 7 through 10
12 Line 6 + Line 11
13 Current Year Line 11 - Prior Year Line 11
14 From Line 12
15 From Line 5
16 Line 14 - Line 15

Narragansett Electric Company
d/b/a National Grid
Docket No. ________
Exhibit -NG-RLO-7
Page 2 of 4

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation Of Net Inflation Adjustment

		(A) As Approved Dkt 09____	(B) CY 2011	(C) CY 2012	(D) CY 2013
1	Four Quarter Average Annual Change - GPD PI		1.69%	2.19%	2.20%
2	Productivity Offset		-0.50%	-0.50%	-0.50%
3	Net Inflation Allowance		1.19%	1.69%	1.70%
4					
5	Total Operating Expenses	218,758,717			
6	Less:				
7	Pension / OPEB expense	(13,581,795)			
8	Commodity Costs Tracker	(9,751,787)			
9	Loss on Reacquired Debt	(686,219)			
10	Depreciation	(41,465,676)			
11	Economic Development Program	(1,000,000)			
12	Net Synergy Expense Adjustments	(850,000)			
13	Environmental and Storm fund collections	(4,119,000)			
14	Inspection & Maintenance Program	(4,676,172)			
15					
16	Net Operating Expenses Subject to Inflation	142,628,068	142,628,068	144,325,342	146,764,440
17					
18	Net Inflation Adjustment		1,697,274	2,439,098	2,494,995
19					
20	Net Operating Expenses Subject to Inflation		144,325,342	146,764,440	149,259,436
21					
22	Cumulative Net Inflation Adjustment		1,697,274	4,136,372	6,631,368

Line Notes

1	Illustrative to be replaced with actual mid-year to mid year inflation rate in report file in November of current year.
2	Productivity offset rate as established in this proceeding, Docket No._____
3	Line 1 + Line 2
5	Total non-income tax operating expenses as approved in this proceeding Docket No._____
7 - 14	As approved in Docket No._____
16	Sum of Lines 5 through 14 for Column (A). All other Years, Prior Year Line 20
18	Line 3 x Line 16
20	Line 16 + Line 18

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Illustrative Computation of Historic Capital Adjustment

Line No.			(A) CY 2009	(B) CY 2010	(C) CY 2011	(D) CY 2012
	Depreciable Net Plan Additions					
1	Actual Capital Spend - Illustrative to be replaced with Actual when known		$59,948,598	$75,931,916	$81,253,000	$87,479,000
2	Beginning of Year CWIP - Actual Dec 31, 2008 amount		$23,263,057	$23,263,057	$23,263,057	$23,263,057
3	End of Year CWIP - Actual Year end amounts when known		$23,263,057	$23,263,057	$23,263,057	$23,263,057
4	Plant Additions (Line 1 + Line 2 - Line 3)		$59,948,598	$75,931,916	$81,253,000	$87,479,000
5	Plant Additions included in base Rates (Sch NG-RLO-2, Page 28, Line 11)		$59,948,598	$75,931,916		
6	Plant Additions not in base rates (Line 4 - Line 5)		$0	$0	$81,253,000	$87,479,000
7						
8	Actual Retirements	1/	8,016,527	10,153,870	12,187,950	13,121,850
9	Retirements reflected in base rates (Sch NG-RLO-2, Page 28, Line 22)		8,016,527	10,153,870		
10	Retirements not in base rates (Line 8 - Line 9)		$0	$0	$12,187,950	$13,121,850
11						
12	Net Depreciable Additions (Line 6 - Line 10)		$0	$0	$69,065,050	$74,357,150
13	Cumulative Net Depreciable Additions (Prior Year Line 13 + Cur Year Line 12)		$0	$0	$69,065,050	$143,422,200
14						
15	Change in Net Plant					
16	Plant Additions (From Line 6)		$0	$0	$81,253,000	$87,479,000
17	Depreciation Expense - from Dkt No.____				41,321,762	41,321,762
18	Incremental Depreciable Amount (Line 10 - Line 11)		0	0	39,931,238	46,157,238
19	Cumulative Depreciable Amount (Prior Year Line 13 + Cur Year Line 12)		$0	$0	$39,931,238	$86,088,476
20						
21	Deferred Tax Calculation:					
22	Composite Book Depreciation Rate - as approved in this proceeding, Dkt - 09-__		3.56%	3.39%	3.39%	3.39%
23	20 YR MACRS Tax Depreciation Rates		3.75%	7.22%	6.68%	6.18%
24	20 YR MACRS Tax Depreciation Rates - 50% Bonus Depreciation		51.88%	3.61%	3.34%	3.09%
25	Vintage Year Tax Depreciation:					
26	2009 Spend	2/	0	0	0	0
27	2010 Spend			0	0	0
28	2011 Spend				3,046,988	5,866,467
29	2012 Spend					3,280,463
30	Annual Tax Depreciation (Sum of Lines 26 through 29)		0	0	3,046,988	9,146,929
31	Cumulative Tax Depreciation (Prior Year Line 31 + Cur Year Line 30)		0	0	3,046,988	12,193,917
32						
33	Book Depreciation (Prior Line 13 x Line 22 +Cur. Line 12 x Line 22 x 50%)		0	0	1,170,653	3,601,659
34	Cumulative Book Depreciation (Prior Year Line 34 + Cur Year Line 33)		0	0	1,170,653	4,772,311
35						
36	Cumulative Book / Tax Timer (Line 31 - Line 34)		0	0	1,876,335	7,421,605
37	Effective Tax Rate		35.000%	35.000%	35.000%	35.000%
38	Deferred Tax Reserve (Line 36 * Line 37)		$0	$0	$656,717	$2,597,562
39						
40	Rate Base Calculation:					
41	Cumulative Incremental Spend (Line 19)		$0	$0	$39,931,238	$86,088,476
42	Accum Depreciation (Line 34 x (-1))		0	0	(1,170,653)	(4,772,311)
43	Deferred Tax Reserve (Line 38 x (-1))		0	0	(656,717)	(2,597,562)
44	Deferred Tax Reversal on 2008 assets		0	0	7,444,836	11,568,759
45	Year End Rate Base (Sum of Lines 41 through 44)		$0	$0	$45,548,704	$90,287,362
46						
47	Revenue Requirement Calculation:					
48	Average Rate Base ((Prior Line 45 + Cur Year Line 45) /2)		$0	$0	$22,774,352	$67,918,033
49	Pre-Tax ROR	3/	12.10%	12.10%	12.10%	12.10%
50	Return and Taxes (Line 48 x Line 49)		0	0	2,755,697	8,218,082
51	Book Depreciation (Line 33)		0	0	1,170,653	3,601,659
52	Annual Revenue Requirement (Line 50 + Line 51)		$0	$0	$3,926,349	$11,819,741

1/ Assumes 15% of Capital Spend to be replaced with actual retirements
2/ Assumes 75% of CY 2009 capital spending qualifies for 50% bonus depreciation deduction
3/ Weighted Average Cost of Capital as approved in this Proceeding Docket No._____

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax Return
Long Term Debt	44.80%	6.79%	3.04%		3.04%
Short Term Debt	5.00%	2.50%	0.13%		0.13%
Preferred Stock	0.20%	4.50%	0.01%		0.01%
Common Equity	50.00%	11.60%	5.80%	3.12%	8.92%
	100.00%		8.98%	3.12%	12.10%

Narragansett Electric Company
d/b/a National Grid
Docket No. ________
Exhibit -NG-RLO-7
Page 4 of 4

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of Current Capital Adjustment

Line No.				2009 Actual Capital Spend	2010 Actual Capital Spend	2 Year Average Actual Spend	Company /Cust Sharing Adj.	(A) CY 2011	2010 Actual Capital Spend	2011 Capital Spend	2 Year Average Actual Spend	Company /Cust Sharing Adj.	CY 2012
	Depreciable Net Plan Additions												
1	Actual Capital Spend - Illustrative to be replaced with Actual when known												
2	Actual Capital Spend - Illustrative to be replaced with Actual when known			$59,948,598	$75,931,916	$67,940,257	75.00%	$50,955,193	$75,931,916	$81,253,000	$78,592,458	75.00%	$58,944,344
3	Beginning of Year CWIP - Actual Dec 31, 2008 amount, then prior year Line 4							$23,263,057					$23,263,057
4	End of Year CWIP - Actual Year end amounts when known							$23,263,057					$23,263,057
5	Plant Additions	(Line 1 + Line 2 - Line 3)						$50,955,193					$58,944,344
6	Retirements		1/					$12,187,950					$13,121,850
7	Net Depreciable Additions	(Line 5 - Line 6)						$38,767,243					$45,822,494
8													
9	Net Rate Base Change												
10	Plant Additions (From Line 4)							$50,955,193					$58,944,344
11	Depreciation Expense - actual 2009 then from Dkt 09-39							41,321,762					41,321,762
12	Incremental Depreciable Amount	(Line 10 - Line 11)						9,633,431					17,622,582
13													
14	Composite Book Depreciation Rate - as approved in this proceeding, Dkt - 09-__							3.39%					3.39%
15	20 YR MACRS Tax Depreciation Rates							3.75%					3.75%
16													
17	Tax Depreciation:	(Line 5 x Line 15)						1,910,820					2,210,413
18													
19	Book Depreciation	(Line 7 x Line 14 x 50%)						657,105					776,691
20													
21	Book / Tax Timer	(Line 17 - Line 19)						1,253,715					1,433,722
22	Effective Tax Rate							35.000%					35.000%
23	Deferred Tax Reserve	(Line 21 x Line 22)						$438,800					$501,803
24													
25	Rate Base Calculation:												
26	Cumulative Incremental Spend	(Line 12)						$9,633,431					$17,622,582
27	Accum Depreciation	(Line 19 x (-1))						(657,105)					(776,691)
28	Deferred Tax Reserve	(Line 23 x (-1))						(438,800)					(501,803)
29	Deferred Tax Reversal on 2008 assets												
30	Year End Rate Base	(Sum of Lines 26 through 29)						$8,537,526					$16,344,088
31													
32	Revenue Requirement Calculation:												
33	Average Rate Base	(Line 30/2)						$4,268,763					$8,172,044
34	Pre-Tax ROR		2/					12.10%					12.10%
35	Return and Taxes	(Line 33 x Line 34)						516,520					988,817
36	Book Depreciation	(Line 19)						657,105					776,691
37	Annual Revenue Requirement	(Line 36 + Line 37)						$1,173,625					$1,765,509

1/ Assumes 15% of Capital Spend to be replaced with actual retirements
2/ Weighted Average Cost of Capital as approved in this Proceeding Docket 09-39

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax Return
Long Term Debt	44.80%	6.79%	3.04%		3.04%
Short Term Debt	5.00%	2.50%	0.13%		0.13%
Preferred Stock	0.20%	4.50%	0.01%		0.01%
Common Equity	50.00%	11.60%	5.80%	3.12%	8.92%
	100.00%		8.98%	3.12%	12.10%

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Division Data Request 7-2

Request:

Re: page 3 of 27, lines 17-19, of the testimony of witness King. Given that the Company is "acutely aware that it is difficult to raise rates for customers, especially in a challenging economic environment," please:

a. Explain the manner in which the Company's proposed rate increase reflects the Company's acute awareness of the challenging economic environment that many of its customers in Rhode Island presently face.

b. Detail the Company justification of its planned capital expenditures for calendar years 2010 through 2012 which, according to witness O'Brien's Schedule NG-RLO-7, page 3 of 4, average more than $80 million per year in the context of the challenging economic environment that its customers face.

c. Please document of all efforts made by the Company to minimize the levels of capital expenditures required over the referenced three year period.

Response:

a. The Company's statement that it is acutely aware of the challenging economic environment is a statement about its awareness of current economic conditions. The Company's request for rate relief is based on its need to increase rates to ensure proper cash flow to support the need for increased investment in the electric distribution system in Rhode Island in order to replace aging infrastructure, and ensure that proper maintenance and operating costs are covered.

b. The planned capital expenditures for 2010 through 2012 are needed to replace aging electric infrastructure and maintain the Company's ability to deliver electricity to customers for their homes and businesses. Despite the difficulty that customers are facing in paying their bills, they are continuing to consume electricity. Therefore, the infrastructure requirements to provide delivery service remain constant despite the economic downturn. The Company's planned capital expenditures are in the interests of customers because the Company must maintain the availability of safe and reliable service, upon which customers rely even in poor economic conditions.

c. The planned capital expenditures represent the Company's estimate as to the level of capital necessary to replace aging infrastructure on the Rhode Island electric delivery system. The Company conducts its capital projects on a cost-effective manner so as to conserve valuable capital resources and enable the completion of as many projects as possible.

Prepared by or under the supervision of: Thomas B. King and John Pettigrew

Division Data Request 7-3

Request:

Re: page 4 of 27, lines 12-14, of the testimony of witness King. Please identify each proposal made by the Company in this proceeding and each element of National Grid's requested revenue requirement for which Commission approval of the Company's proposal as filed is essential if National Grid is to maintain its ability to meet the service quality mandates established by the Commission.

Response:

The Company's service quality mandates include reliability and customer service performance metrics. In order to meet these mandates, the Company needs timely recovery of both operations and maintenance and capital expenditures. The Company's proposals in this proceeding are all designed to provide the Company with this timely recovery. In addition, by recovering the costs for items outside of its control, such as commodity bad debt and pension/OPEB costs, through a reconciling tracker, the Company maintains its ability to direct its resources to its underlying service obligations.

Division Data Request 7-4

Request:

Re: page 4 of 27, line 16, of the testimony of witness King. Please provide the data, analyses, customer surveys and other studies upon which the Company relies to assess "*the changing demands of its customers*."

Response:

The Company gains an understanding of the changing demands of customers through its daily interactions with customers on a broad range of issues including service requirements, billing and collection, energy efficiency programs and community relations and outreach. The input gained through these interactions is factored into the Company's business plan and objectives as those plans are continually pursued.

Prepared by or under the supervision of: Rudolph L. Wynter

Division Data Request 7-6

Request:

Re: page 8 of 27, lines 1-2, of the testimony of witness King. Please:

a. Indicate aspects of the desires of the Company's customers for cost-effective, reliable, and safe electric service that are unique or different from those of the vast majority of electric customers through the U.S.

b. Provide the data, analyses, customer surveys, studies and other documents upon which the witness relies to assert that the Company's customers "*want access to information and assistance on a wide variety of energy products*."

c. For each rate class, identify the types of information and assistance that customers want and to which they do not currently have access.

d. For each rate class, identify the energy products for which customers most commonly want more information.

Response:

a. The statement referenced in Mr. King's testimony at page 8, lines 1-2 does not state that the "desires of the Company's customers for cost-effective, reliable, and safe electric service" are unique or different from other customers in the U.S. The statement is that "customers want cost-effective, reliable and safe electric service" and "information and assistance on a wide variety of energy products" and that the Company "is in a unique position to provide both." This statement is true because, as the provider of electric delivery service, the Company is uniquely situated in terms of its direct contact with customers. This contact involves the physical infrastructure providing safe and reliable service, as well as a range of customer transactions that provide the opportunity to convey information on public safety, energy use and conservation assistance and other energy-related matters.

b. See the Company's response to item (c), below.

c. As one example, National Grid provides a web-based portal called "Energy Profiler Online" ("EPO") that provides customers 15-minute load data, which enables self-management of energy usage. There are approximately 540 customers enrolled in this program, of which 154 are located in Rhode Island. In Rhode Island, there are approximately 1,084 large customer accounts that could

Division Data Request 7-6 (cont.)

utilize this program. Participation in this program indicates to the Company that there is a desire to access more information than is available on the customer bill regarding a customer's energy usage. In addition, many EPO subscribers have requested that the Company develop a way to provide more frequent updates (i.e., more real-time data) so that they can utilize the functionality of this service to alert them to the occurrence of their own peak loads while they are occurring.

For medium-sized accounts, customers have asked the Company to provide interval metering and EPO service (which is not currently offered to these customers). These services would allow customers to take advantage of competitive options for time-based supply pricing and otherwise manage their loads and/or participate in demand response opportunities.

Small C&I and residential customers have made requests about access to hourly pricing or the availability of demand response programs, which would be dependent on the Company's ability to implement advanced meters for use by these rate classes. There is significant evidence that customers who have access to both real time usage data and hourly pricing tariffs will reduce their energy usage and will shift their energy consumption from peak to off-peak periods. There is also evidence that customers who have access to this type of information will have a higher level of customer satisfaction.

Information regarding small customer interest in energy products is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/may202009/a_faruqui-brattle.pdf (see pages 36-39)

Also, please see Attachment DIV 7-6, as reported by Utility Pulse 2009.

d. The Company's customers are active participants in energy efficiency programs. On May 1, 2009, National Grid filed the "National Grid Gas and Electric Demand-Side Management Program 2008 Year End Report" in Commission Dockets 3790 and 3892. For the electric side of the Company's business, the report shows that 289 large commercial and industrial customers, 531 small business customers, and 47,626 residential customers participated in the Company's electric energy efficiency programs. Typically, about three times as many customers contact the Company and its vendors and trade allies for information about programs as participate. Therefore, a summary of the customer inquiries to the Company on electric energy saving measures is as follows:

Division Data Request 7-6 (cont.)

- Approximately 900 customers requested information about large C&I energy saving measures;
- Approximately 1,500 customers requested information about small C&I energy saving measures; and
- Approximately 143,000 customers requested information about residential energy saving measures.

Importance of Energy Efficiency

Support

Importance of Utility Providing Energy Efficiency (Tools & Resources)

Very Important/ Important	Very Unimportant/ Unimportant	Index
75%	14%	536

Source: Utility Pulse 2009

nationalgrid
The power of action.

Division Data Request 7-7

Request:

Re: page 8 of 27, lines 13-15, of the testimony of witness King. Please:

a. Provide the data, analyses, and studies upon which the Company relies to conclude that utilities are the most appropriate conduit for economic development programs for business needing assistance in growing or maintaining their business in the service area;

b. Indicate the extent to which the Company and its shareholders are willing to contribute to the costs of providing economic development programs for businesses operating within its Rhode Island service territory in need of assistance in growing or maintaining their business;

c. Explain why businesses in the Company's service territory who do not participate in economic development programs should bear added costs to enable the Company to fund utility sponsored economic development programs.

Response:

a. The Company can be an effective provider of economic development services by helping business customers and augmenting the activities of existing economic development entities in New England. Utilities are widely recognized as effective and appropriate economic development partners, as evidenced by the large number of utilities who provide these services. There are currently approximately 65 investor-owned utilities that participate in the Utility Economic Development Association, covering a large portion of the U.S. and parts of Canada. It is not the Company's intent to displace existing economic development resources in Rhode Island, nor to supplant the roles of existing economic development agencies. Rather, the Company is proposing to develop programs that will complement and supplement existing economic development resources in Rhode Island. The Company's proposed collaborative program development process is intended to identify program and collaborative opportunities that will increase the overall impact and effectiveness of state, regional and local economic development efforts.

   There is considerable anecdotal information on the value of utilities in economic development, including the information set forth in Attachment DIV 7-7(a). Attachment DIV 7-7(a) was published by Platts, which is a highly regarded publication principally covering the energy industry. The article is entitled

Division Data Request 7-7 (cont.)

"Partnering for Success"-Revitalized Economic Development Adds Value to the Bottom Line." (January 2004).

b. The benefits arising from an economic development program are intended to assist the broader interests of Rhode Island and the Company's customers within Rhode Island. Therefore, the Company is not proposing that shareholders offer the program. The program that is conducted in New York, on which the Company's program is based, provides for 100 percent recovery through rates. Regulators in New York and other jurisdictions have recognized the benefit of these programs. The Company recognizes that this is a policy decision for the Commission and that consideration of the proposal will require a balancing of interests between the cost associated with the programs and the potential benefits. The Company has made the proposal to further that type of discussion. Please see Attachment DIV 7-7(b) for a copy of an assessment prepared in relation to the New York program.

c. Please see the response to item (b), above.

Prepared by or under the supervision of: Carmen Fields

Impact of National Grid Assistance in New York

Grant recipients were asked to provide feedback on the role National Grid funding played in the completion and timing of their project. As presented in Table 6, the majority of respondents indicated that the grant did have an impact in terms of providing an incentive for the project and/or leading the respondent to complete the project sooner than they otherwise would have.

TABLE 6 -- GRANT IMPACTS

	Capital Investment	Energy Efficiency & Productivity	Site Development	Revitalization & Urban Dev	Marketing Programs
Did National Grid funding lead you to :					
Take actions you would not have otherwise taken	64%	82%	90%	70%	100%
Take actions more quickly	79%	82%	90%	70%	100%

Leveraged Funds

Respondents were asked to report on the mix of funding they received from sources other than National Grid, including local, state and federal programs.

As indicated in Table 7, grant recipients in the Site Development and Revitalization/Urban Development programs report the broadest range of funding sources, with local and state government programs tapped most frequently. Local funding was utilized most often for Capital Investment grant recipients, while Marketing projects typically obtained matching funds from state programs. Energy Efficiency/Productivity program participants were least likely to obtain funding from other sources, which is an expected outcome – most of these are smaller projects that do not involve a larger business expansion, and the customer’s own investment is the only required source of program matching funds.

The $5.9 million dollars in grant funds released by National Grid during 2007 represents approximately 2 percent of the total costs ($300 million) of projects funded during the year, including all public and private investment.

TABLE 7 -- SOURCES OF LEVERAGED FUNDS

Program Category	**Local Gov't**	**State Gov't**	**Fed Gov't**
Capital Investment	36%	21%	-
Marketing	23%	54%	15%
Energy Efficiency & Productivity	-	18%	-
Site Development	60%	50%	10%
Revitalization & Urban Dev	60%	60%	10%

Customer Operational Impacts

Grant recipients in the capital investment, revitalization/urban development and energy efficiency/productivity programs were asked about the project impacts in terms of cost savings, increased productivity, increased sales, and improved power quality and/or reliability.

As presented in Table 8, energy efficiency savings and productivity gains are the most commonly recognized benefits, even in the programs that are not focused on the installation of energy efficiency measures. Power quality and reliability improvements also were frequently sited, particularly among revitalization and urban redevelopment grant recipients. Half of the capital investment grant awardees reported an increase in annual sales as a result of their project, which is to be expected due to the business expansion orientation of these programs.

TABLE 8 -- OPERATIONAL BENEFITS

	Capital Investment	Revitalization & Urban Dev	Energy Efficiency & Productivity
Project Benefits:			
cut costs thru energy efficiency	71%	80%	91%
increase productivity	71%	60%	64%
improve power quality or reliability	64%	70%	82%
increase in annual sales	50%	40%	36%

Regional Economic Impacts

The survey also asked grantees to report on the impact of their projects in terms of new capital investment, new and retained jobs, and other measures.

Capital investment is perhaps the single most important metric for the National Grid Economic Development Plan. Not only is it directly tied to regional economic output, but companies who decide to invest here in many cases have chosen their Upstate New York facility over other competing corporate locations. The flow of capital among facilities is a good leading indicator of their relative long-term viability, particularly for manufacturing companies with facilities in multiple states.

Many of the Company's EDP programs include eligibility requirements and funding guidelines that are tied to investment in energy infrastructure, new building construction and/or purchase of machinery and equipment. The Company tracks investment impacts through the annual survey process, and the survey information is supplemented with data obtained through the project verification process that occurs before the release of grant funds. This process involves a detailed review of paid invoices, receipts and other documentation, which is summarized and compared to information provided on the approved application. New capital investment is not an eligibility requirement for the EDP marketing programs, and investment impacts are not tracked for those projects, as discussed below.

Tables 9 & 10 summarize the capital investment impacts of EDP funding for 2007, and the cumulative investment impacts since the inception of the programs. The total investment associated with 2007 projects was over $325 million, with the majority resulting from projects in the capital investment programs. Since 2003, a total of over $700 million has been invested in projects funded through the EDP.

TABLE 9 -- CAPITAL INVESTMENT IMPACTS – 2007

Program Category	**2007 Investment**
Capital Investment Programs	$265,862,800
Energy Efficiency & Productivity Programs	$2,275,329
Site Development Programs	$36,007,400
Revitalization & Urban Development Programs	$21,665,276
TOTAL	**$325,810,805**

Table 10 -- CUMULATIVE CAPITAL INVESTMENT IMPACTS - 2003-2007

Program Category	2003-2007 Investment
Capital Investment Programs	$381,284,602
Energy Efficiency & Productivity Programs	$24,092,865
Site Development Programs	$260,490,400
Revitalization & Urban Development Programs	$39,892,676
TOTAL	**$705,760,543**

Employment impacts are also an important long-term objective of National Grid's economic development activities. The creation and retention of jobs is one of the most visible indicators of a healthy economy and a strong community, and it is also the most important measure from a political perspective. However, job creation is not necessarily a priority for expanding businesses, many of whom make investments in new technology, machinery and equipment in order to REDUCE the labor content of their products or services, and to increase productivity.

Unlike many federal and state economic development programs, job creation/retention performance generally is not an eligibility requirement for National Grid EDP programs. The Company collects "projected" employment data from applicants when they apply for funding, and job creation potential is among the project evaluation criteria for several programs. "Actual" employment impacts are gathered through the annual survey of grant recipients, and this information is supplemented by press releases (from the company and/or New York State), commercially available databases, and other secondary sources. Job creation and retention results are not tracked for EDP marketing programs, as discussed below.

Tables 11 and 12 summarize the job creation and retention impacts of EDP funding for 2007, and cumulative employment impacts since program inception. The total job creation and retention benefit associated with 2007 projects was 3,406, with most of those impacts generated through the capital investment programs. Since 2003 over 10,000 jobs have been created or retained in projects funded through the National Grid EDP.

TABLE 11 -- JOB CREATION AND RETENTION IMPACTS - 2007

Program Category	2007 JOBS
Capital Investment Programs	2,721
Energy Efficiency & Productivity Programs	373
Site Development Programs	147
Revitalization & Urban Development Programs	165
TOTAL	**3,406**

Table 12 -- CUMULATIVE JOB CREATION AND RETENTION IMPACTS - 2003-2007

Program Category	2003-2007 JOBS
Capital Investment Programs	8,217
Energy Efficiency & Productivity Programs	588
Site Development Programs	1,018
Revitalization & Urban Development Programs	375
TOTAL	**10,198**

Marketing Results

Table 13 summarizes the types of marketing activities funded by the EDP in 2007. The creation and distribution of printed materials was the most commonly funded initiative, followed by website projects and print advertising.

TABLE 13 -- 2007 EDP FUNDED MARKETING ACTIVITIES

Activity	Completed Projects
Create & Distribute Print Materials	14
Website Improvements/Redesign	7
Create/Distribute CD/DVD	1
Print Advertising	5
Sales Calls	3
Direct Mail	4
Lead Identification and Qualification	3
Internet Advertising	4
TV & Radio Advertising	3
Telemarketing	2
Marketing Through Realtor	1

Applicants for marketing assistance are asked to formulate goals for each marketing initiative, including capital investment and new jobs, and potential economic impact is among the criteria used to evaluate marketing applications. However, while it is understood that successful strategic marketing will ultimately lead to business attraction and expansion projects, the long-term nature of economic development marketing initiatives makes it unreasonable to expect new jobs and capital investment in the near term.

The results of the EDP marketing programs are more reasonably measured in terms of marketing progress, i.e. responses, leads, prospect visits and project commitments. The Company collects this information through the annual survey. Table 14 summarizes the marketing results reported by EDP grant recipients for 2007 projects.

TABLE 14 -- MARKETING PROGRESS – 2007

Marketing Results	
Marketing responses	2,695
Leads	1,062
Prospect Visits/Meetings	462
Project Commitments	15

The annual survey also asks marketing & site development grant recipients for information on their target markets. As presented in Table 15, the majority of 2007 marketing activities were focused on attracting new businesses from outside New York State. 35% of respondents reported that they marketed to an audience within the state, although more than half of those reported that they also targeted markets outside of New York.

TABLE 15 PRIMARY TARGET MARKETS

Geographic Region	Primary Target
Total Marketing Outside New York State	**65%**
Out of state, within US	39%
Canada	17%
Other International	9%
Total Marketing within NY State	**35%**
Local/Regional/Upstate NY	26%
Elsewhere in NY state	9%

Division Data Request 7-9

Request:

Re: page 10 of 27, line 16, through page 11 of 27, line 7, of the testimony of witness King. Please identify:

a. The location of the referenced LEED Gold office building;

b. A listing of each LEED certified building that the Company owns or leases in Rhode Island, providing the address, square feet of building space, and level of LEED certification for each building;

c. Provide the most recent Energy Star rating for each of the buildings that the Company currently owns or occupies in Rhode Island;

d. For each building for which no current or recent Energy Star rating is presently available, please explain why National Grid has not made a priority of obtaining Energy Star ratings for the building to date and provide the target date by which the Company will commit to obtaining such a rating;

e. Indicate whether the Company has committed or is willing to commit to annual redetermination of the Energy Star rating for each of its buildings in Rhode Island; and

f. Explain how a utility can be a cost-effective and efficient provider of services if it has not already demonstrated the commitment to assess the energy efficiency of its own buildings.

Response:

a. The building is located at 40 Sylvan Road, Waltham, MA 02451

b. National Grid does not currently own any LEED-certified buildings in Rhode Island.

c. The Company is not aware of any type of Energy Star ratings for buildings.

d. Please see the response to item (c), above.

e. Please see the response to item (c), above.

Prepared by or under the supervision of: John Pettigrew

Division Data Request DIV 7-9 (cont.)

f. There are many ways for a utility to be a cost-effective and efficient provider of services, including assessing the energy efficiency of its own buildings.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 7-10

Request:

Re: page 12 of 27, lines 9-13, of the testimony of witness King. Please reconcile the representation that "*National Grid will continue to fulfill its responsibilities in the regulatory compact by providing safe and reliable services cost-effectively*" with the witness' statement at page 6 of 27, lines 13-14 that "*there is a risk the Company will be unable to meets its service quality mandates as established by the Commission*."

Response:

In this response, the Company believes that the question refers to a quote that appears on lines 13-14 of page 4, not page 6, of 27.

On page 12, the witness is discussing the achievement of National Grid's vision. In stating this vision and working toward it, the Company assumes that it will have cost recovery. On page 4, the witness is discussing the importance of establishing new rates in this proceeding to enable the Company to meet its service quality mandates as established by the Commission.

Prepared by or under the supervision of: Thomas B. King

Division Data Request 7-11

Request:

Re: page 13 of 27, lines 3-5, of the testimony of witness King. Please explain the witness' use of the term "*competitively*" in the context of the referenced portion of his testimony, and identify with whom or what the Company must maintain a competitive posture when it is a monopoly provider of electric delivery services in Rhode Island.

Response:

The use of the term "competitively" does not refer to the provision of electric delivery service. It refers to the intensely competitive market for capital in which the Company competes to locate funding to make the investments needed to serve customers, as discussed on page 17 of 27 of the pre-filed testimony of Thomas B. King.

Prepared by or under the supervision of: Thomas B. King

Division Data Request 7-12

Request:

Re: pages 13 -14, of the testimony of witness King. Please detail the actions the Company has taken, and/or plans to take to obtain federal funds for its Rhode Island service territory under the provisions of the American Recovery and Reinvestment Act (ARRA).

Response:

The Company has developed a Smart Grid Pilot Program that it filed with the Commission on Tuesday, July 21, 2009. The Company intends to include that plan in an application to the U.S. Department of Energy for ARRA funding.

Prepared by or under the supervision of: Thomas B. King

Division Data Request 7-13

Request:

Re: page 16 of 27, line 10, of the testimony of witness King. Is it the witness' intent to suggest that the Company is acting unilaterally to modernize its regulatory compact with the state of Rhode Island? If not please, explain the meaning of the referenced statement.

Response:

No. As noted on page 16 of 27, lines 3-4, the Company believes "[t]his is a journey we are taking with the Commission, the Division, and other stakeholders."

Prepared by or under the supervision of: Thomas B. King

Division Data Request 7-15

Request:

Re: page 17 of 27, lines 16-18, of the testimony of witness King. Please explain why the purported "*global and intensely competitive market for capital*" does **not** suggest that minimizing the Company's capital needs should be a priority.

Response:

The discussion of the global and intensely competitive market for capital explains that when the Company needs to secure capital, it must go to a global market for it. This is inapposite to the Company's need to replace aging infrastructure, which it tries to do as cost-effectively as possible.

Prepared by or under the supervision of: Thomas B. King

Division Data Request 7-16

Request:

Re: page 18 of 27, lines 9-13, of the testimony of witness King. Please:

a. Verify that if the Company's proposals in this proceeding are adopted as presented, National Grid's tariff in Rhode Island will include nine separate rate adjustment provisions.

b. Provide the criteria the Company uses to assess the reasonable and practical limits on the number of rate adjustments that can be included in the Company's Rhode Island tariff.

Response:

a. If the Company's proposals in this proceeding are adopted as presented, National Grid's tariff in Rhode Island will include nine separate rate adjustment provisions. These adjustments are:

   1. Standard Offer Adjustment Provision (R.I.P.U.C. No. 2014 – pending approval)
   2. Distribution Adjustment Provision (R.I.P.U.C. No. 2015 – pending approval)
   3. Pension/OPEB Adjustment Provision (R.I.P.U.C. No. 2016 – pending approval)
   4. Revenue Decoupling Mechanism Provision (R.I.P.U.C. No. 2017 – pending approval)
   5. Inspection and Maintenance Cost Adjustment Provision (R.I.P.U.C. No. 2018 – pending approval)
   6. Transmission Service Charge Adjustment (R.I.P.U.C. No. 1189)
   7. Transition Charge Adjustment (R.I.P.U.C. No. 1188)
   8. Conservation and Load Management Adjustment (R.I.P.U.C. No. 887)
   9. Customer Credit Provision (R.I.P.U.C. No. 1185)

b. When determining the appropriateness of proposing new rate adjustments, the Company considers factors such as the availability of the internal resources necessary to accurately bill customers, to effectively communicate the billing information to customers, and to accurately track and report the necessary information in order to make complete and timely regulatory compliance filings. The Company also considers the ease of review by customers and whether the potential for customer confusion is minimized.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 7-17

Request:

Re: page 18 of 27, lines 19-22, of the testimony of witness King. Please:

a. Indicate the whether the percentages cited for Standard Offer Service and Last Resort Service customers by rate class reflect numbers of customers, kWh usage, or some other measure of service;

b. Provide the most recent data available for the percentages of kWh use and numbers of customers in each rate class that utilize (i) Standard Offer Service and (ii) Last Resort Service.

Response:

a. The percentages cited for Standard Offer Service ("SOS") and Last Resort Service ("LRS") on page 18 of 27, lines 19-22, of Mr. King's testimony reflect numbers of customers receiving SOS and LRS as of April 2009.

b. Attachment DIV 7-17(b) shows the percentage of total customers receiving SOS and LRS and the percentage of SOS and LRS kWh deliveries for the billing month of May 2009.

Prepared by or under the supervision of: Howard S. Gorman

The Narragansett Electric Company
Standard Offer & Last Resort kWh and Number of Customers by Rate Class
As of June 2009
Source: Monthly Revenue Reports

	Number of Customers		kWh	
Rate Class	Standard Offer	Last Resort	Standard Offer	Last Resort
A16	99.73%	0.13%	99.39%	0.18%
A60	99.81%	0.19%	99.76%	0.24%
B32	50.00%	0.00%	8.58%	0.00%
B62	50.00%	0.00%	21.92%	0.00%
C06	91.13%	0.70%	89.45%	0.97%
C08	67.59%	0.66%	70.57%	0.35%
E30	0.00%	0.00%	0.00%	0.00%
E40	62.50%	12.50%	80.13%	18.15%
G02	79.95%	2.28%	71.32%	2.91%
G32	52.05%	5.58%	39.20%	5.49%
G62	45.45%	0.00%	57.89%	0.00%
M1	0.00%	0.00%	0.00%	0.00%
R02	0.00%	0.00%	0.00%	0.00%
S10	89.51%	1.11%	84.01%	1.75%
S14	53.92%	4.05%	9.33%	2.94%
T06	0.00%	0.00%	0.00%	0.00%
X01	0.00%	0.00%	0.00%	0.00%
Total	98.31%	0.24%	70.96%	2.28%

Division Data Request 7-18

Request:

Re: page 20 of 27, lines 1-4, of the testimony of witness King. Please provide the date(s), analyses, and studies upon which the witness relies to assess the "*potential for commodity prices to resume their upward climb*" and identify the timeframe witness King believes that higher commodity prices would likely be in effect.

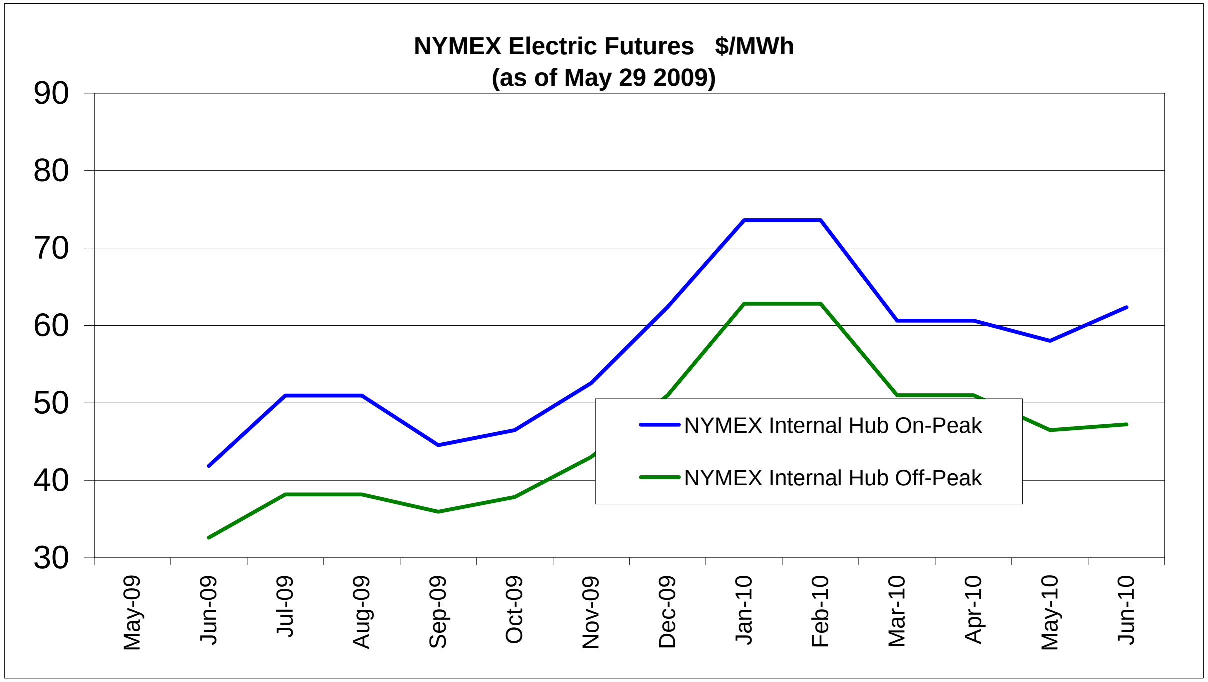
Response:

The NYMEX Electric Futures for ISO-NE Internal Hub are a liquid trading point for all New England zones. As of May 29, 2009, these prices show a significant rise in prices through 2009 and 2010. The prices remain at this high level throughout the next few years.

Attachment DIV 7-18 presents a graph of the ISO-NE Internal Hub prices for On-Peak and Off-Peak hours.

Attachment DIV 7-18

	May-2009	Jun-2009	Jul-2009	Aug-2009	Sep-2009	Oct-2009	Nov-2009	Dec-2009	Jan-2010	Feb-2010	Mar-2010	Apr-2010	May-2010	Jun-2010
NYMEX Internal Hub On-Peak		41.8	50.9	50.9	44.5	46.5	52.6	62.4	73.6	73.6	60.6	60.6	58.0	62.4
NYMEX Internal Hub Off-Peak		32.6	38.2	38.2	36.0	37.9	43.0	51.0	62.8	62.8	51.0	51.0	46.5	47.3



May-2010	Jun-2010	Jul-2010	Aug-2010	Sep-2010	Oct-2010	Nov-2010	Dec-2010	Jan-2011	Feb-2011	Mar-2011	Apr-2011	May-2011	Jun-2011	Jul-2011
58.0	62.4	71.5	71.5	61.3	66.1	66.1	66.1	86.1	86.1	69.9	69.9	64.0	70.0	78.4
46.5	47.3	51.8	51.8	47.0	53.8	53.8	53.8	72.1	72.1	56.9	56.9	50.4	51.4	61.6

Aug-2011	Sep-2011	Oct-2011	Nov-2011	Dec-2011	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Jul-2012	Aug-2012	Sep-2012	Oct-2012
78.4	67.8	70.5	70.5	70.5	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1
61.6	52.4	54.9	54.9	54.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9

Nov-2012	Dec-2012	Jan-2013	Feb-2013	Mar-2013	Apr-2013	May-2013	Jun-2013	Jul-2013	Aug-2013	Sep-2013	Oct-2013	Nov-2013	Dec-2013	Jan-2014
76.1	76.1	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	80.9
59.9	59.9	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	63.0

Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Nov-2014	Dec-2014
80.9	80.9	80.9	80.9	80.9	80.9	80.9	80.9	80.9	80.9	80.9
63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0

Division Data Request 7-20

Request:

Re: page 23 of 27, lines 3-7, of the testimony of witness King. Please:

a. Explain why National Grid's customers should be required to subsidize public policy initiatives that the Company's shareholders will not subsidize.

b. Explain why the Commission should not show the same sensitivity to providing the "*right business environment to attract investment dollars*" for the Company's commercial and industrial customers that National Grid seeks for its shareholders."

Response:

a. Energy efficiency and other climate change initiatives are for the benefit of customers. Therefore, it is appropriate that customers should pay for these initiatives.

b. The Company does not understand this question. The Company anticipates that the Commission will show sensitivity to all customers.

Division Data Request 7-21

Request:

Re: page 23 of 27, line 20, of the testimony of witness King. Please provide the witness' understanding of what would constitute "*minimum compliance*" in the context of his discussion of ratemaking and incentives.

Response:

Although I am not a lawyer, my understanding is that the Company is in minimum compliance when it is meeting any legal and regulatory requirements, but not taking any extra, discretionary steps towards the objective behind those requirements. As Dr. Tierney discusses in her testimony at pages 33-34 of 97, whether there are direct rewards or direct negative consequences associated with compliance will impact decision making:

> If you knew that (a) there were different degrees of compliance or fulfillment of an objective (such as delivering cost-effective energy efficiency programs to your customers) and (b) for each level of accomplishment on the margin, there was also a direct negative impact (e.g., loss of revenues for the Company), you might decide to balance the interests of the customers and the company at some point and fall short of maximum fulfillment of implementing all cost-effective energy efficiency for your customers. If, on the other hand, you knew that your Company's revenues were not tied to sales, this tension would not exist and you would push on the margin to fulfill the goal for the customer. Even better, to the extent that the Company is rewarded financially for stellar performance in implementing cost-effective energy efficiency, one would expect to see the company stretching to accomplish that objective.

Prepared by or under the supervision of: Thomas B. King

Division Data Request 8-3

Request:

Please provide a map of your Rhode Island service territory.

Response:

Please see Attachment DIV 8-3 for a map of the Rhode Island Service territory.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Division Data Request 8-4

Request:

Historical sales revenue by customer class and number of bills. Please refer to Excel spreadsheet: *Data Request Narragansett-RIPUC Sales Rev 063009.xls*.

Response:

Please see Attachment DIV 8-4. The Company is providing Attachment DIV 8-4 also in EXCEL format.

Prepared by or under the supervision of: Howard S. Gorman

Narragansett Electric Co. **Residential & Non-Residential Customers** Data request for Monticello Consulting--Narragansett Electric Co. RIPUC Docket 4065

2007	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total 2007
Residential Sales Revenue	$ 40,223,826.79	$ 35,847,974.62	$ 35,150,147.98	$ 30,986,959.01	$ 27,935,790.15	$ 31,114,810.95	$ 37,183,065.79	$ 43,761,019.53	$ 39,428,217.59	$ 31,705,927.49	$ 30,269,118.56	$38,105,373.10	$ 421,712,231.56
Number of Bills-Residential	424,875	425,462	426,208	426,216	425,827	425,144	424,519	424,164	423,808	423,354	423,376	424,344	
Average Residential Bill $	$ 94.67	$ 84.26	$ 82.47	$ 72.70	$ 65.60	$ 73.19	$ 87.59	$ 103.17	$ 93.03	$ 74.89	$ 71.49	$ 89.80	
Non-Residential Sales Revenue	$ 44,258,503.01	$ 38,875,807.57	$ 40,621,904.24	$ 37,469,116.73	$ 38,006,244.87	$ 40,876,798.96	$ 42,337,828.45	$ 45,205,270.29	$ 44,760,235.42	$ 42,556,330.54	$ 39,631,985.49	$40,021,229.15	$ 494,621,254.72
Number of Bills-Non-Residential	55,823	55,554	55,998	56,092	56,133	56,191	56,190	56,220	56,276	56,296	56,500	56,595	
Average Non-Residential Bill $	$ 792.84	$ 699.78	$ 725.42	$ 667.99	$ 677.07	$ 727.46	$ 753.48	$ 804.08	$ 795.37	$ 755.94	$ 701.45	$ 707.15	

2008	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total 2008
Residential Sales Revenue	$ 40,357,051.97	$ 39,510,921.59	$ 37,777,532.33	$ 33,615,050.84	$ 29,158,536.30	$ 33,645,509.99	$ 46,344,177.73	$ 59,634,713.74	$ 48,427,812.10	$ 38,749,498.41	$ 40,084,901.03	$46,436,901.06	$ 493,742,607.09
Number of Bills-Residential	413,501	428,948	428,598	415,808	428,765	430,363	429,223	428,147	428,289	427,561	429,672	415,731	
Average Residential Bill $	$ 97.60	$ 92.11	$ 88.14	$ 80.84	$ 68.01	$ 78.18	$ 107.97	$ 139.29	$ 113.07	$ 90.63	$ 93.29	$ 111.70	
Non-Residential Sales Revenue	$ 42,967,396.36	$ 43,255,760.32	$ 38,633,314.42	$ 46,914,460.40	$ 38,536,491.55	$ 42,579,663.30	$ 47,902,376.31	$ 60,328,833.62	$ 68,822,839.77	$ 62,015,227.16	$ 34,039,266.29	$46,230,591.55	$ 572,226,221.05
Number of Bills-Non-Residential	57,759	59,491	59,490	58,292	59,642	59,652	59,737	59,723	59,393	59,553	59,897	58,184	
Average Non-Residential Bill $	$ 743.91	$ 727.10	$ 649.41	$ 804.82	$ 646.13	$ 713.80	$ 801.89	$ 1,010.14	$ 1,158.77	$ 1,041.35	$ 568.30	$ 794.56	

YTD 2009	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	YTD Total 2009
Residential Sales Revenue	$ 54,445,530.45	$ 39,855,857.73	$ 38,119,977.73	$ 35,803,828.37	$ 30,982,989.74	$ 31,587,624.03	$ -	$ -	$ -	$ -	$ -	$ -	$ 230,795,808.05
Number of Bills-Residential	428,796	429,632	430,305	429,777	430,760	422,293	-	-	-	-	-	-	
Average Residential Bill $	$ 126.97	$ 92.77	$ 88.59	$ 83.31	$ 71.93	$ 74.80							
Non-Residential Sales Revenue	$ 51,908,261.95	$ 42,216,714.97	$ 39,719,225.59	$ 35,201,172.55	$ 37,530,204.71	$ 35,924,110.24							$ 242,499,690.01
Number of Bills-Non-Residential	59,378	59,986	59,950	59,770	59,785	59,204	-	-	-	-	-	-	
Average Non-Residential Bill $	$ 874.20	$ 703.78	$ 662.54	$ 588.94	$ 627.75	$ 606.79							

Division Data Request 8-5

Request:

Please indicate your DSO data (Days Sales Outstanding) by month for 2007, 2008 and YTD May 2009, with the following breakdown:

a. Residential accounts
b. Non-residential accounts

Response:

Please see Attachment DIV 8-5.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

NARRAGANSETT ELECTRIC
DSO (Days Sales Outstanding)
2007, 2008 & YTD May 2009

Revenue Year	Res / Comm Indicator		Revenue Month 1	2	3	4	5	6	7	8	9	10	11	12
2007	R		44.2	42.9	44.0	42.8	39.5	40.6	45.4	48.6	46.0	41.7	38.6	44.7
2007	C		32.4	28.7	30.9	28.7	27.1	28.9	32.0	32.4	34.7	33.7	30.2	34.0
2008	R	**(1)**	50.6	50.5	49.9	49.1	43.0	44.6	48.9	55.9	52.8	44.4	45.6	49.9
2008	C	**(1)**	36.1	40.5	38.0	38.2	33.0	34.2	33.2	39.0	44.2	45.2	32.7	31.5
2009	R		55.0	49.5	45.3	43.8	40.4							
2009	C		34.0	29.3	25.1	22.5	24.8							

(1) January 2008 was the CSS conversion month. An estimate was made for the revenue that month.

Division Data Request 8-8

Request:

Please provide detailed information around any credit, risk or behavioral scoring system currently in use, which assists your organization in selecting or prioritizing accounts for collection and/or termination activity.

Response:

National Grid uses Portfolio Management Package (PMP) as its behavioral scoring system. PMP is a product of Experian that is integrated with the National Grid's Customer Service System (CSS). PMP aids in prioritizing delinquent accounts based on behavior/risk and in using the most effective collection activities prior to disconnect notice.

Process Description:

Every business day, National Grid's customer service system creates data files and sends them to Experian for all billing accounts with bills that will be due in 2 days in the future. The data files contain information that is used by Experian in scoring the accounts.

Experian takes and processes the files, and returns a feedback file containing the processed accounts along with their Experian Strategy code. This code is a 4 digit strategy code used to identify the most appropriate Collection Treatment path for that account. There is a collection treatment path assigned to each strategy code.

4 digit strategy code breakdown:

Position 1 of Strategy Code: Champion/Challenger Assignment
- A = Champion (50% of Population)
- B = Challenger (50% of Population)

Different collection treatment paths are assigned to Champion and Challenger. Half of the population is assigned to get the Champion path and the other half to get the Challenger path. This allows us to measure the effectiveness of different treatments.

Division Data Request 8-8 (cont.)

Position 2 of Strategy Code: Delinquency Level

- 0 = Current
- 1 = 1 Cycle Past Due
- 2 = 2 Cycles Past Due
- 3 = 3 Cycles Past Due
- 4 = 4+ Cycles Past Due

Position 3 of Strategy Code: Risk Grades

- A = Top 25% of Population
- B = 2nd 25% of Population
- C = 3rd 25% of Population
- D = Bottom 11-25% of Population
- E = Bottom 10% of Population

Position 4 of Strategy Code: Balance Grades

- 1 = <$50
- 2 = $50-$99.99
- 3 = $100.00-249.99
- 4 = $250.00-999.99
- 5 = $1000.00+

Example # 1:
Account assigned with a Strategy Code A4C2: This account is assigned a Champion collection path. The account is 4+ cycles past due. The account has C risk grade and its balance grade is between $50 and $99.99.

Currently, an account with A4C2 strategy code receives an outbound call and then 12 business days after, gets a disconnect notice.

Example # 2:
Account assigned with a Strategy Code B4C2: This account is assigned a Challenger collection path. The account is 4+ cycles past due. The account has C risk grade and its balance grade is between $50 and $99.99.

Currently, an account with B4C2 strategy code receives a disconnect notice. The account does not get an outbound call.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Division Data Request 8-11

Request:

Do you assess a fee to any customer to reconnect the service after a termination for non-payment?

a. If yes, what is the fee?

Response:

Pursuant to § 20 of the Company's Terms and Conditions for Distribution Service, R.I.P.U.C. No. 1197, the Company charges a $10 fee for the reconnection of service subsequent to termination for non-payment.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Division Data Request 9-1

Request:

Does the Company install distribution voltage regulators and capacitors to provide voltage support on its distribution system? If so, do those voltage regulators and capacitors provide voltage support for the entire distribution system or just for the secondary portion of that system?

Response:

The Company installs both voltage regulators and capacitors on its “primary” distribution system. The distribution primary voltages range from 4.16kV to 34.5kV and there are hundreds of primary feeders (circuits) that are routed throughout the service territory between substations and the numerous transformers that step the voltage down to utilization voltages used by our customers. Voltage regulators and capacitor banks can be applied on individual feeders and/or at a substation bus that supplies multiple feeders. Although the voltage regulation is applied at the primary level, the intent of voltage regulation is to ensure voltage is maintained within appropriate tolerance at the point of customer connection.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 9-2

Request:

Does the Company record its investment in distribution voltage regulators and capacitors in Account 368, Line Transformers? If so, please state the plant-in-service figures associated with those investments. If not, please identify the FERC account or accounts in which the cost of distribution voltage regulators and capacitors are recorded and provide the plant-in-service figures for each.

Response:

Yes, the Company records its investment in distribution voltage regulators and capacitors in Account 368, Line Transformers. The plant-in-service investments in each as of December 31, 2008 are shown below:

Capacitors	$4,869,381
Voltage Regulators	$481,491

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 9-3

Request:

The Company's response to Division Data Request 2-11 part e states that "… the transformer unit costs shown on Schedule NG-HSG-2, page 35, include equipment, material and overhead costs …" There are no transformer unit costs on page 35 of Schedule NG-HSG-2. Please provide a corrected reference.

Response:

The transformer costs are found in Schedule NG-HSG-2, page 17.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-4

Request:

Are any of the customers in the 200 kW and/or 3,000 kW demand rate classes served at secondary voltages? If so, how is this consistent with the NCP allocation values on Page 2 of Schedule NG-HSG-2 at line 7 showing the NCP demands for customers at the secondary voltage level in these two rate classes are zero?

Response:

Large commercial and industrial (C&I) customers are served directly from the primary voltage facilities, utilizing a step-down line transformer and service drop from the transformer to their building. Therefore, the large C&I classes (Rate G-32, B-32, G-62, B-62, X-01) receive no allocation of secondary facilities in the allocation study.

Division Data Request 9-5

Request:

If none of the customers in the 200 kW and/or 3,000 kW demand rate classes are served at secondary voltages, why is a portion of the Company's investment in line transformers allocated to these classes?

Response:

As indicated in the response to Division Data Request 9-4, large commercial and industrial are served directly from primary voltage facilities through a step-down line transformer and service drop. The customers taking service on Rates G-32, B-32, G-62 and B-62 have the option of owning their own transformers or utilizing Company owned line transformers to transform primary delivery voltages to the appropriate voltage level for the facility. The allocation of line transformers to these classes represents Company owned transformers that are serving customers in these rate classes.

Division Data Request 9-6

Request:

The Company's response to Division Data Request 2-11 part b states that "… the current replacement cost of each transformer type was allocated among the rate classes based on the number of customers served." At the secondary level, the average NCP demand for customers in the General C&I rate class is 38 kW. Why is it reasonable to allocate the cost of 10 or 25 kVA transformers to General C&I rate class customers?

Response:

The transformer study shows the actual number of customers served by different transformer types. If the cost of any particular size transformer is allocated to a rate class, it is because there are customers in that rate class that are served by that size transformer, therefore it is reasonable to allocate transformer costs to those customers.

Division Data Request 9-7

Request:

The units for the demand allocation values at lines 5-7 on page 2 of Schedule NG-HSG-2 are shown as Megawatts (MW)? Are the units for these demands actually kilowatts (kW)?

Response:

Yes, the demand allocation values at lines 5-7 on page 2 of Schedule NG-HSG-2 should be labeled 'kW' for kilowatts. This has no effect on the results of the class allocated cost of service study.

Division Data Request 9-8

Request:

With respect to the Company's response to Division Data Request 2-12 and its description of the analyses presented on pages 18-19 of Schedule NG-HSG-2, do the Company's accounting records show the service drop configuration, transformer size, and rate class for each and every one of the Company's customers? If not, was the analysis referred to on pages 18-19 of Schedule NG-HSG-2 and in Workpaper NG-HSG-2 based upon a sample of the Company's customers' service configurations?

Response:

No. The Company's Geographic Information System ("GIS") contains information related to each transformer in service on the system. This information was "linked" to the Company's billing system through a premise identification number to obtain specific customer information, including rate class. GIS also contains information related to the type, length and number of service drops on the system. However, unlike transformers, information related to service drops cannot be linked to specific transformers or customers. The information extracted from the GIS was used to provide a basis for the service drop types to be included in the study and an estimate the length of the various service drops types to be used to develop pricing for each service drop type.

Using the average lengths extracted from GIS, broad rate categories (residential and commercial), different construction environments (OH, UG, URD, Conventional UG), and engineering judgment; seven primary service types were defined and each rate class was mapped into one or more of these service types (in many cases the classes were split by percentages to account for different construction environments). These seven service types were also priced out the STORMS work management system using the currently available and most common conductor sizes to determine the cost to install each type.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-9

Request:

If the response to question 8 indicates that actual accounting records showing service configurations, transformer types, and rate class data exist for each and every one of the Company's customers, do those data also indicate the number of customers of a given rate class connected to different types of transformers, separately for each service drop configuration? If so, please provide copies of these data in machine-readable form.

Response:

Please see the response to Division Data Request 9-8. The Company's accounting records do not contain the information identified.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-10

Request:

Regarding the development of Account 903 Allocator on page 24 of Schedule NG-HSG-2, are the total 2008 amounts in the lines 1-8 a breakdown of the various expenses recorded in Account 903 for that year? If no, please explain.

Response:

Yes. The amounts on lines 1 through 8 of Schedule NG-HSG-2 reflect the expense components of Account 903.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-11

Request:

Regarding the development of Account 908 Allocator on page 25 of Schedule NG-HSG-2, are the total 2008 amounts in the lines 1-6 a breakdown of the various expenses recorded in Account 908 for that year? If no, please explain.

Response:

Yes. The amounts on lines 1 through 6 of Schedule NG-HSG-2 reflect the expense components of Account 908, with the exception of Demand Side Management program costs shown on line 8, which have been removed.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-12

Request:

Regarding the development of Account 910 Allocator on page 26 of Schedule NG-HSG-2, are the total 2008 amounts in the lines 1-4 a breakdown of the various expenses recorded in Account 910 for that year? If no, please explain.

Response:

Yes. The amounts on lines 1 through 4 on Page 26 of Schedule NG-HSG-2 reflect the expense components of Account 910.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-13

Request:

Please provide the cost basis, with all supporting documentation, for the proposed $5.11/kW-month backup distribution charge in C&I Back-Up Service Rate (B-32).

a. Please explain why this charge is over twice the distribution charge per kW in excess of 200 kW for supplemental service.

Response:

The proposed Rate B-32 backup service demand charge of $5.11 is set at the current charge and the Company has not proposed an adjustment to the charge in this filing. This rate was approved in Docket No. 3617.

The backup charges for Rate B-32 consist of a monthly customer charge identical to the customer charge of the companion general service Rate G-32, and a Backup Service per kW charge.

The design of the Rate B-32 backup service rates provide the Company with the same revenue from a backup service customer as from an all requirements customer with similar usage characteristics, because the Company is required to make the same investment in distribution facilities to serve both customers. The Company does not assess per kWh charges on volumes generated by the customer, therefore, the backup service per kW charge is larger than the equivalent full service demand charge, in order to collect the same revenue from the customer who receives his entire load from the Company and the customer who generates his own load.

Division Data Request 9-14

Request:

If Rate B-32 backup customers were transferred to Rate G-32 per the statement on page 21, lines 10-13, of Mr. Gorman's testimony, would all backup service be charged all the rate components set forth on the Cover Sheet of Rate G-32 on an "as-used" basis?.

Response:

Under the circumstances identified in Mr. Gorman's testimony regarding Commission approval of the proposed Revenue Decoupling Ratemaking Plan presented in the prefiled direct testimony of Susan F. Tierney, and if the Company proposes, and the Commission approves, the elimination of Backup Service Rate B-32, then customers currently on Rate B-32 would be transferred to Rate G-32 and would be billed on the same basis as is proposed for Rate G-32, under which customers are assessed a customer charge and distribution demand charges for monthly demand in excess of 200 kW and distribution energy charges only for actual use of the distribution system.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-15

Request:

Please refer to page 2 of 12 of Schedule NG-HSG-6, which shows the rate design for Residential Rates A16 and A60:

a. Is it correct that the proposed rates and the resulting revenues in the last two columns would provide total distribution rate revenue of $150,521,686, which is approximately equal to the Proposed Distribution Charges of $150,507,000 on line 50 of page 2 of Schedule NG-HSG-4, that would result in the combined residential classes paying their full cost of service?

b. Are the rates paid by customers taking service under Rate Schedule A-60 less than the cost of serving these customers? If so, please provide the amount of the subsidy being received by the A-60 customers at the Company's proposed rates.

c. Since the combined residential classes are paying their full cost of service, does this mean that the subsidy provided to A-60 customers is being entirely paid for by A-1 6 customers?

d. If the answer to (c) is yes, please explain why only A-16 customers should bear all of this subsidy rather than all customers classes bearing a proportional responsibility for the A-60 subsidy.

Response:

a. Yes. The difference between total distribution rate revenue of $150,521,686 for Residential Rates A16 and A60 on schedule NG-HSG-6, page 2, line 21 under the proposed rates, and Proposed Distribution Charges of $150,507,000 for Residential Rates A16 and A60 on Schedule NG-HSG-4, page 2, line 50, is due to rounding.

b. Residential Rate A-16 and Residential Low Income Rate A-60 are combined in the Allocated Cost of Service Study because their usage profiles are similar. Therefore the cost to serve a Rate A-16 and a Rate A-60 customer with the same usage is the same, and because the Rate A-60 customer pays less than the Rate A-16 customer, the Rate A-60 customer is paying less than its full cost of service. Rate A-60 customers are paying approximately $4,795,000 less than their cost of service.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-15 (cont.)

c. Yes.

d. It is appropriate for the rate design to treat Rate A-16 and Rate A-60 on a combined basis because customers migrating into or out of Rate A-16 are almost always coming from or going to Rate A-60, and vice versa. Although in other jurisdictions in which National Grid operates, the low income discount is recovered from all retail delivery service customers, the Company notes that in some jurisdictions the low income discount is recovered from only other residential customers. Today, the low income discount is recovered from all of the Company's rate classes, and the Company would not object to recovering the proposed Rate A-60 discount from all rate classes on a reasonable basis.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-16

Request:

Rate schedules “3000 kW Backup Service Rate (B-62)” and “3000 kW Demand Rate (G-62)” appear to be stricken in Schedule NG-HSG-12, and they do not appear in the clean version of the Company’s proposed Retail Delivery Service Tariffs in Schedule NG-HSG-11.

a. Please confirm that these two rate schedules are proposed to be withdrawn.

b. Please confirm that customers currently taking service under these two rate schedules will take service under either the “C&I Backup Service Rate (B-32)” or the “200 kW Demand Rate (G-32)” under the Company’s proposal.

c. If parts (a) and (b), above, are confirmed, please explain why the class “3000 kW Demand” is separated out in the class cost of service study.

d. Reference is made in Mr. Gorman’s testimony (e.g., at page 32, line 9) to the “C&I Large Demand rate class.” Does this refer to the group of all customers currently taking service under rate schedules B-32, G-32, B-62 and G-62?

   (i) Will all the customers in this class take service under rate schedules B-32 and G-32 under the Company’s proposal?

Response:

a. Yes, the Company is proposing to eliminate 3,000 kW Demand Rate G-62 and 3,000 kW Backup Service Rate B-62, and transfer existing customers to Rates G-32 and Rate B-32, respectively.

b. Yes, see the response to item (a) above.

c. Rate classes G-62 and B-62 are separated out in the class cost of service study because the information to do so was readily available. The analysis shows that the cost structures for Rate G-62 and Rate G-32 are similar and support the Company’s proposal to eliminate Rate G-62.

d. Yes, in Mr. Gorman’s testimony “C&I Large Demand rate class” comprises the current rate classes B-32, G-32, B-62 and G-62.

   (i) Yes.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-17

Request:

Please provide all calculations, analyses and backup data that show that the Rate M-01 charge of $4,406.03 per customer-month yields revenue equal to the cost of serving these customers.

Response:

Rate M-01 customers are merchant generators that are interconnected directly or indirectly with high voltage facilities at 115 kV or greater. The M-01 tariff was approved by the Commission in Docket No.3243 and the rates applicable to this class were the result of a settlement in that docket and were not based on an allocated cost study. The Company is proposing to increase the distribution charge by the overall average increase of 29.4%.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-18

Request:

Referring to page 36, lines 1-6 of Mr. Gorman's testimony and Schedule NG-HSG-8, page 1, please provide all calculations, analyses and backup data that show the basis in costs for the $2.50/ kW-month High Voltage Delivery (115 kV) discount and the $2.50/ kW-month Second feeder Service Rate.

Response:

The calculation of the proposed High Voltage Delivery (115 kV) (HVD) discount and the Second Feeder Service (SFS) charge are based upon the allocated cost of the primary distribution system; however, they are also designed to mitigate large rate impacts. The High Voltage Delivery -115kV ("HVD") discount applies to customers who receive service at not less than 115,000 volts and do not need a line transformer. Therefore, these customers do not use any the primary or secondary distribution system. The Second Feeder Service ("SFS") charge applies to customers requiring a second primary distribution feeder.

Customers taking service on Rates B-32, G-32, B-62 and G-62, and who take service delivery at 115kV, are eligible for the HVD115kV discount. As indicated above, these customers do not use any primary distribution facilities. Therefore, the HVD credit is based on the allocation of the primary distribution revenue requirement for Rate B-32/G-32/B-62/G-62 on a per kW basis, or $5.96 per kW-month of actual demand (Schedule NG-HSG-1, page 47, line 2).

The current and proposed SFS is set at the same level as the HVD 115kV based on the assumption that the HVD115kV represents the cost of the facilities necessary to provide second feeder capability.

Currently there are no customers receiving the HVD115kV discount. However, there are currently five customers receiving SFS. To mitigate a significant rate impacts to these customers, the HVD discount and the SFS charge are proposed to increase from $2.41 per kW-month to $2.50 per kW-month. Projected revenue from SFS charge is $379,000. Any increase to the proposed SFS charge and HVD115kV would result in only a slight decrease in the charges of all other Rate B-32 / G-32 / B-62 / G-62 customers. Therefore, the Company is not proposing a fully cost based rate for SFS.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 9-19

Request:

Line 6, page 1 of Schedule NG-HSG-7 refers to "Coincident Peak with NEP's Peak kW," which were taken from Schedule NG-HSG-56-2, page 30. Please confirm that the12 CPs at 115 kV on page 30 of Schedule NG-HSG-56-2 are at the times of NEP's monthly system peaks and not at the times of Narragansett's monthly coincident peaks.

Response:

The12 CPs at 115 kV on page 30 of Schedule NG-HSG-2 are at the times of Narragansett's monthly coincident peaks. However, the allocator should have been developed at the time of NEP's peak. Although the demands are the same for six out twelve months in 2008, the Company will submit an update to its schedules correcting for the error.

Division Data Request 10-3

Request:

Please provide a schedule similar to Schedule NSG-HSG-6, Pages 10-12, but at present rates.

Response:

Schedule NG-HSG-6, Pages 10-11, provides Proof of Distribution Revenue at Proposed Rates. The Company has provided a similar schedule, Proof of Distribution Revenue at Current Rates, in Schedule NG-HSG-2, Pages 7-10. Please see Attachment DIV 10-3 for pages 7-10 of Schedule NG-HSG-2.

Prepared by or under the supervision of: Howard S. Gorman

Revenue
7-10

Proof of Distribution Revenue at Current Rates

	Code	Description	Includes	Annual Bills	Pro-rate Factor	Prorated Annual Bills	Monthly Customer Charge	Customer Charge Revenue	Billing Demand	Prorate Factor	Prorated Billing Demand	Demand Charge	Demand Charge Revenue
1	A16	Residential	A16-A60	5,126,632		5,108,506		12,994,875					
2	C06	Small C&I	C06-R2	536,788		539,107		3,189,287					
3	G02	General C&I	G02-E40	85,684		86,973		8,991,571	3,812,972		3,747,594		12,067,252
4	G32	200 kW Demand	B32-G32	14,962		15,489		3,662,023	5,940,055		5,901,279		11,767,149
5	G62	3000 kW Demand	B62-G62	152		152		2,610,127	1,304,312		1,301,916		2,890,254
6	S10	Lighting	S10-S14	41,532		41,532		9,579,339					
7	X01	Propulsion	X01	12		12		120,000					
8				5,805,762		5,791,771		41,147,221	11,057,339		10,950,789		26,724,656
9	A16	Residential Basic		4,743,535	(0.382%)	4,725,409	$2.75	12,994,875					
10	A60	Resid. Low Income	A16	383,097	-	383,097	-	-					
11	B32	C&I Back-up	G32	19	-	19	$236.43	4,492	23,335	(0.020%)	23,330	See below	70,031
12	B62	3000 kW Back-up	G62	24	-	24	$17,118.72	408,967	378,188	(0.176%)	377,521	See below	838,096
13	C06	Small C&I		525,892	0.445%	528,231	$6.00	3,169,384					
14	C06	Small C&I Unmetrd	C06	3,528	(0.325%)	3,517	$1.83	6,435					
15	E40	Storage Cooling	G02	73	10.571%	81	$75.15	6,066					
16	G02	General C&I		85,611	1.496%	86,892	$103.41	8,985,505	3,812,972	(1.715%)	3,747,594	$3.22	12,067,252
17	G32	200 kW Demand		14,943	3.526%	15,470	$236.43	3,657,531	5,916,720	(0.655%)	5,877,949	$1.99	11,697,118
18	G62	3000 kW Demand		128	0.759%	129	$17,118.72	2,201,160	926,124	(0.187%)	924,396	$2.22	2,052,159
20	R02	Traffic Signals	C06	7,368	(0.115%)	7,360	$1.83	13,468					
21	S10	Private Lighting	Lighting	36,475		36,475		885,317					
22	S14	Streetlighting	Lighting	5,057		5,057		8,694,022					
23	X01	X-01		12		12	$10,000.00	120,000					
24				5,805,762		5,791,771		41,147,221	11,057,339		10,950,789		26,724,656

Revenue
7-10

Proof of Distribution Revenue at Current Rates

	Code	Description	Includes	kWh Deliveries	kWh Charge	kWh Charge Revenue	HVD Billing Units	HVD Credit Revenue	HVM Billing Units	HVM Credit Revenue	Feeder Service Billing Units	Feeder Service Revenue	Normalized Rate Year Revenue
1	A16	Residential	A16-A60	3,037,613,124		100,110,475							113,105,349
2	C06	Small C&I	C06-R2	552,428,873		20,047,322							23,236,609
3	G02	General C&I	G02-E40	1,371,693,627		10,688,581	97,801	(36,186)	31,685,574	(3,725)			31,707,493
4	G32	200 kW Demand	B32-G32	2,041,538,285		18,149,275	1,641,134	(607,220)	33,578,448	(79,954)	151,469	365,040	33,256,314
5	G62	3000 kW Demand	B62-G62	565,377,847		-	990,034	(366,313)	5,500,381	(53,781)			5,080,288
6	S10	Lighting	S10-S14	68,381,640		(745,321)							8,834,018
7	X01	Propulsion	X01	25,935,238		80,918							200,918
8				7,662,968,634		148,331,249	2,728,969	(1,009,719)	70,764,403	(137,460)	151,469	365,040	215,420,989
9	A16	Residential Basic		2,842,813,980	$0.03376	95,973,400							108,968,275
10	A60	Resid. Low Income	A16	194,799,144	See below	4,137,075							4,137,075
11	B32	C&I Back-up	G32	5,245,253	$0.00889	46,630	10,444	(3,864)	121,154	(1,018)			116,272
12	B62	3000 kW Back-up	G62	140,107,795	-	-	100,014	(37,005)	1,247,063	(11,610)			1,198,448
13	C06	Small C&I		545,545,940	See below	19,782,828							22,952,211
14	C06	Small C&I Unmetrd	C06	2,304,213	See below	98,562							104,997
15	E40	Storage Cooling	G02	3,248,747	See below	55,764							61,830
16	G02	General C&I		1,368,444,880	$0.00777	10,632,817	97,801	(36,186)	31,685,574	(3,725)			31,645,663
17	G32	200 kW Demand		2,036,293,032	$0.00889	18,102,645	1,630,690	(603,355)	33,457,294	(78,937)	151,469	365,040	33,140,042
18	G62	3000 kW Demand		425,270,052	-	-	890,020	(329,307)	4,253,318	(42,171)			3,881,840
20	R02	Traffic Signals	C06	4,578,720	$0.03624	165,933							179,401
21	S10	Private Lighting	Lighting	9,917,952	See below	(225,168)							660,149
22	S14	Streetlighting	Lighting	58,463,688	See below	(520,153)							8,173,869
23	X01	X-01		25,935,238	$0.00312	80,918							200,918
24				7,662,968,634		148,331,249	2,728,969	(1,009,719)	70,764,403	(137,460)	151,469	365,040	215,420,989
													215,542,992
							Rate	($0.37)			Rate	$2.41	215,420,369

Revenue
7-10

Proof of Distribution Revenue at Current Rates

	Code	Description	Includes	Annual Bills	Pro-rate Factor	Prorated Annual Bills	Monthly Customer Charge	Customer Charge Revenue	Billing Demand	Prorate Factor	Prorated Billing Demand	Demand Charge	Demand Charge Revenue
		A-60 Residential Low Income											
25		Dec-Mar	First 450										
26		Dec-Mar	Next 750										
27		Dec-Mar	Over 1200										
28		Apr-Nov	First 450										
29		Apr-Nov	Over 450										
30													
		B-32 C&I Back-up											
31		Back-up							7,567	(0.020%)	7,565	$5.11	38,659
32		Supplemental							15,768	(0.020%)	15,765	$1.99	31,372
33									23,335		23,330		70,031
		B-62 3000 kW Back-up											
34		Back-up							93,570	(0.176%)	93,405	$2.22	207,359
35		Supplemental							284,618	(0.176%)	284,116	$2.22	630,737
36									378,188		377,521		838,096
		C-6 Small C&I											
37		kWh											
38		Over 25 kVA											
39													
		C-8 Small C&I Unmetered											
40		kWh											
41		Over 25 kVA											
42													
		E-40 Storage Cooling											
43		On Peak											
44		Off Peak											
45													
		S-10 Private Lighting											
46		Blackstone Valley											
47		Narragansett zone											
48		Newport Zone											
49													
		S-14 General Streetlighting											
50		Blackstone Valley											
51		Narragansett zone											
52		Newport Zone											
53													

Revenue
7-10

Proof of Distribution Revenue at Current Rates

	Code	Description	Includes	kWh Deliveries	kWh Charge	kWh Charge Revenue	HVD Billing Units	HVD Credit Revenue	HVM Billing Units	HVM Credit Revenue	Feeder Service Billing Units	Feeder Service Revenue	Normalized Rate Year Revenue
		A-60 Residential Low Income											
25		Dec-Mar	First 450	44,572,797	$0.01688	752,389							
26		Dec-Mar	Next 750	19,367,637	$0.03055	591,681							
27		Dec-Mar	Over 1200	5,991,574	$0.02548	152,665							
28		Apr-Nov	First 450	85,907,219	$0.01688	1,450,114							
29		Apr-Nov	Over 450	38,959,917	$0.03055	1,190,225							
30				194,799,144		4,137,075							
		B-32 C&I Back-up											
31		Back-up											
32		Supplemental											
33													
		B-62 3000 kW Back-up											
34		Back-up											
35		Supplemental											
36													
		C-6 Small C&I											
37		kWh		545,538,492	$0.03624	19,770,315							
38		Over 25 kVA		7,448	$1.68000	12,513							
39				545,545,940		19,782,828							
		C-8 Small C&I Unmetered											
40		kWh		2,295,053	$0.03624	83,173							
41		Over 25 kVA		9,160	$1.68000	15,389							
42				2,304,213		98,562							
		E-40 Storage Cooling											
43		On Peak		1,571,117	$0.02536	39,844							
44		Off Peak		1,677,630	$0.00949	15,921							
45				3,248,747		55,764							
		S-10 Private Lighting											
46		Blackstone Valley		3,983,976	($0.04420)	(176,092)							
47		Narragansett zone		4,252,128	-	-							
48		Newport Zone		1,681,848	($0.02918)	(49,076)							
49				9,917,952		(225,168)							
		S-14 General Streetlighting											
50		Blackstone Valley		9,491,748	($0.04420)	(419,535)							
51		Narragansett zone		45,523,752	-	-							
52		Newport Zone		3,448,188	($0.02918)	(100,618)							
53				58,463,688		(520,153)							

Division Data Request 10-4

Request:

Referring to Schedule NSG-HSG-6, Pages 10-12, please provide the actual test year billing determinants for each rate class.

Response:

Please see Attachment DIV 10-4 for the actual test year billing determinants for each rate class.

Prepared by or under the supervision of: Howard S. Gorman

Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4065
Attachment 1 to DIV 10-4

Narragansett Electric Company
2008 Billing Determinants

Line No.	Rate Class (a)	No. of Bills (b)	kWh (c)	kWh - Peak (d)	kWh - Off Peak (e)	kWh Applicable to Water Heater Credit (f)	kVA - Minimum Bill Provision (g)	kW (h)	kW-Backup (i)	kW-Supplemental (j)	kW - Second Feeder Service (k)	Fixtures (l)	kW - HVD Credit (m)	HVM Credit[1] (n)
1	A-16	4,736,327	2,823,490,295											
2	A-60	366,373	191,498,118			3,875,737								
3	B-32	33	6,292,247					28,118.2	9,010.4	19,107.8			11,135	($4,855)
4	B-62	24						388,938.4	96,101.5	292,836.9			106,203	($73,373)
5	C-06	547,477	540,108,677				7,375							
6	C-08	3,248	2,176,865				8,724							
7	E-30	148	1,611,773											
8	E-40	105	3,075,838	1,487,089	1,588,749									
9	G-02	100,811	1,379,210,237					3,854,102.0					57,428	($22,437)
10	G-32	12,163	2,083,491,465					5,884,789.0			155,277		1,621,138	($519,546)
11	G-62	145	437,613,249					953,246.0					918,336	($483,195)
12	M-1	35	1,311,811											
13	R-2	6,977	4,321,938											
14	S-10		1,075,930									6,105		
15	S-14		6,388,916									106,033		
16	T-06 Residential	1,766	7,625,601											
17	T-06 Commercial	787	5,718,849											
18	X-01	12	25,611,410					194,335						
19	Total	5,776,431	7,520,623,219	1,487,089	1,588,749	3,875,737	16,099	11,303,528.6	105,111.9	311,944.7	155,277	112,138	2,714,240	($1,103,407)

Note 1: Actual HVM Credit provided to customers

Division Data Request 10-6

Request:

Please provide the actual number of customers and kWh sales by customer class for each month January 2006 until the most recent month available. The response should be provided in Excel version

Response:

Please see Attachment DIV 10-6, which is also provided in EXCEL format. Page 1 reflects monthly kWh deliveries and Page 2 presents customer count.

Prepared by or under the supervision of: Howard S. Gorman

Narragansett Electric Company
kWh by Rate Class

Rate Class	Jan-2006	Feb-2006	Mar-2006	Apr-2006	May-2006	Jun-2006	Jul-2006	Aug-2006	Sep-2006	Oct-2006	Nov-2006	Dec-2006
A-16	263,314,722	218,233,922	234,124,169	196,778,205	177,923,350	203,118,067	272,165,578	319,098,671	236,224,351	195,882,836	194,428,504	233,798,876
A-60	21,869,329	19,145,563	21,344,348	17,973,987	16,162,005	17,798,356	23,254,681	26,741,120	19,427,473	16,369,839	16,831,495	20,156,318
B-32	13,200	12,800	503,400	220,400	235,400	9,600	642,200	382,800	298,800	267,800	221,200	258,800
B-62	12,227,200	11,286,800	10,991,600	11,152,000	9,851,600	11,356,000	11,424,000	12,593,600	12,683,600	11,336,400	10,249,200	11,553,600
C-06	47,553,762	41,707,566	46,255,591	40,373,137	37,968,453	42,029,061	50,322,705	55,506,372	46,442,052	40,970,084	39,256,959	43,690,258
E-30	234,719	193,245	232,879	160,202	102,634	90,735	88,467	92,815	89,997	46,761	146,918	159,204
E-40	300,020	360,820	248,120	332,920	378,520	500,800	860,060	972,540	680,320	434,060	263,480	151,120
G-02	118,510,565	104,858,828	117,149,111	105,216,194	102,853,503	114,358,802	129,308,719	140,668,979	125,996,043	111,138,916	105,749,875	115,136,137
G-32	178,935,181	161,081,814	189,132,447	168,055,636	160,632,753	178,575,789	184,880,058	199,995,253	187,961,527	174,621,453	163,188,393	183,993,251
G-62	33,580,000	33,388,300	38,863,700	34,009,300	31,790,700	32,764,100	40,040,800	31,165,300	47,875,200	35,932,266	34,793,500	40,992,300
M-01	22,000	(22,000)	969,000	769,000	557,000	466,000	484,000	53,000	554,000	344,000	107,000	464,000
R-02	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560
S-10	1,134,542	965,058	1,039,767	792,849	703,123	701,603	652,347	683,092	848,318	880,262	974,684	1,178,256
S-14	6,166,892	5,267,911	5,603,800	4,336,306	3,855,222	3,869,381	3,581,538	3,725,326	4,705,978	4,903,671	5,353,799	6,518,219
T-06	877,508	584,817	683,000	461,066	336,600	375,352	923,249	448,437	387,192	384,712	437,560	584,713
T-08	762,530	715,075	797,372	563,412	378,412	392,556	431,736	478,602	432,672	405,797	431,129	477,434
T-10	207,812	179,267	192,370	120,472	91,681	89,452	80,788	90,572	87,158	80,681	94,821	124,319
X-01	1,038,600	1,524,600	1,836,000	1,971,000	1,918,800	2,057,400	1,931,400	1,744,200	1,902,600	2,017,800	1,881,000	2,197,800
Total	687,130,142	599,865,946	670,348,234	583,667,646	546,121,316	608,934,614	721,453,886	794,822,239	686,978,841	596,398,898	574,791,077	661,816,165

Rate Class	Jan-2007	Feb-2007	Mar-2007	Apr-2007	May-2007	Jun-2007	Jul-2007	Aug-2007	Sep-2007	Oct-2007	Nov-2007	Dec-2007
A-16	260,041,148	240,443,858	236,216,220	207,511,842	186,766,719	209,532,024	251,972,976	297,346,693	267,266,116	213,575,391	205,515,879	260,368,889
A-60	22,214,170	21,067,426	20,274,677	17,669,031	15,719,937	16,981,324	19,909,192	23,818,633	21,456,151	17,393,027	13,951,571	17,374,533
B-32	297,200	271,000	292,000	264,800	310,200	395,400	387,400	377,000	354,600	11,200	2,396,600	434,800
B-62	11,490,000	12,368,000	11,636,800	11,016,400	10,354,400	11,854,000	11,422,400	12,634,000	13,114,000	11,886,000	11,389,600	12,735,200
C-06	45,477,706	45,780,312	46,866,725	42,644,501	40,414,805	42,304,524	48,395,723	52,931,904	50,457,596	43,447,795	40,221,735	47,098,654
E-30	178,126	213,904	295,033	159,278	116,823	86,071	80,746	85,981	79,539	76,604	110,160	208,791
E-40	60,020	24,720	31,120	10,340	49,600	608,600	610,840	679,100	468,880	648,280	250,040	135,700
G-02	120,379,550	109,252,060	113,447,096	105,971,363	103,781,906	117,113,534	126,014,762	135,896,941	130,956,143	119,000,057	111,596,235	116,986,066
G-32	180,162,535	163,414,942	173,194,005	166,983,914	167,040,706	183,446,184	178,606,334	192,710,807	192,047,007	184,170,747	172,905,800	178,078,515
G-62	45,988,500	31,744,800	38,359,000	29,533,600	42,215,300	37,780,600	34,729,800	37,312,760	39,640,200	42,584,400	40,294,185	38,829,740
M-01	622,000	505,000	443,000	435,000	420,000	306,000	569,000	97,000	-	-	93,000	-
R-02	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560
S-10	1,221,688	978,522	874,527	780,483	673,069	681,348	620,931	647,361	814,082	852,511	962,408	1,131,005
S-14	6,790,540	5,485,005	4,941,920	4,421,261	3,853,450	3,892,631	3,582,286	2,319,070	4,722,093	4,905,263	5,559,913	6,544,083
T-06	651,414	781,203	818,350	584,737	478,625	342,643	358,926	375,208	381,702	392,848	434,937	713,566
T-08	674,161	688,909	671,672	675,612	448,149	328,125	487,531	414,284	410,804	408,318	371,041	617,984
T-10	145,131	162,752	148,683	115,823	87,138	72,113	73,979	75,681	78,972	66,792	89,861	132,859
X-01	2,082,600	2,116,800	1,985,400	2,025,000	2,008,800	2,194,200	2,019,600	2,064,600	2,100,600	2,102,400	2,008,800	2,300,400
Total	698,858,049	635,680,773	650,877,788	591,184,545	575,121,187	628,300,881	680,223,986	760,168,583	724,730,045	641,903,193	608,533,325	684,072,345

Rate Class	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
A-16	271,688,526	243,953,523	232,945,362	206,674,531	178,736,685	207,620,217	283,091,278	317,096,757	246,439,003	197,416,070	202,495,545	235,332,798
A-60	18,421,742	17,173,572	16,382,145	14,844,028	12,481,799	14,184,513	19,090,059	21,129,273	16,315,921	11,249,830	13,943,263	16,281,973
B-32	436,689	448,879	236,537	678,582	352,121	208,574	892,490	707,466	511,426	377,688	396,033	412,882
B-62	12,123,200	11,196,586	10,459,620	11,326,667	11,339,756	12,518,751	12,075,472	9,830,830	13,748,086	14,181,204	13,670,079	11,345,676
C-06	58,279,774	37,257,759	45,468,256	42,152,510	37,604,354	42,304,219	50,146,709	55,492,152	48,587,319	39,921,086	41,559,393	43,528,110
E-30	235,938	226,139	203,794	170,033	98,778	89,966	75,992	85,796	73,615	68,367	106,769	176,586
E-40	58,061	42,728	27,284	125,389	202,835	461,308	731,584	491,233	395,519	430,945	109,621	13,752
G-02	117,071,943	116,745,511	109,607,921	115,672,386	93,195,637	110,869,086	128,815,209	139,379,338	134,413,152	202,418,549	10,072,666	104,944,839
G-32	178,225,546	178,846,713	160,360,842	189,647,430	161,227,883	169,581,617	175,491,240	192,127,740	229,604,408	141,044,346	163,587,262	147,744,718
G-62	37,686,584	30,265,941	8,293,004	59,349,940	33,126,433	38,650,151	31,529,853	45,323,227	47,333,488	38,956,809	29,023,926	38,073,893
M-01	197,000	380,000	-	415,351			5,960	85,260		214,640		13,600
R-02	124,778	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560
S-10	1,220,576	899,800	888,956	734,359	670,835	611,316	671,466	648,655	818,132	873,046	927,087	1,075,930
S-14	7,205,912	5,292,950	5,188,710	4,348,147	3,822,381	3,621,167	3,964,165	3,839,132	4,855,625	5,185,541	5,500,578	6,388,916
T-06	941,615	1,588,613	1,462,527	1,221,814	961,695	771,884	784,094	936,624	890,252	805,543	1,010,976	1,352,665
T-08	528,281											
T-10	87,867											
X-01	2,190,600	2,012,709	2,017,206	2,037,548	2,117,434	2,336,459	1,699,098	2,524,480	2,235,074	2,084,985	2,297,260	2,058,557
Total	706,724,632	646,712,983	593,923,724	649,780,275	536,320,186	604,210,788	709,446,229	790,079,523	746,602,580	655,610,209	485,082,018	609,126,455

Rate Class	Jan-2009	Feb-2009	Mar-2009	Apr-2009	May-2009	Jun-2009
A-16	292,965,947	237,413,336	225,676,559	210,741,843	181,635,491	186,176,352
A-60	20,220,908	17,421,958	18,311,685	18,416,228	15,993,968	15,559,616
B-32	450,507	425,720	319,238	(623,593)	1,267,416	477,222
B-62	12,048,322	8,224,016	14,239,583	(45,592,240)	65,468,187	10,656,254
C-06	59,595,170	47,771,078	46,397,868	44,974,552	40,066,435	40,679,442
E-30	228,625					
E-40	63,154	57,724	38,026	90,568	222,556	159,995
G-02	117,391,044	111,093,765	109,046,731	103,715,254	99,533,327	102,296,355
G-32	199,395,109	172,781,074	161,166,627	169,216,445	152,482,783	161,167,239
G-62	42,361,847	34,726,524	26,182,123	40,118,884	27,619,636	36,285,175
M-01	137,450	298,340		378,520		52,970
R-02	381,560	256,052				
S-10	1,081,792	974,702	841,477	733,686	601,470	654,399
S-14	6,406,511	5,817,887	5,013,553	4,442,371	3,646,642	3,949,115
T-06	1,687,879	64,648	(80)			
T-08						
T-10						
X-01	2,479,535	2,047,602	2,105,117	2,295,498	2,201,782	1,963,967
Total	756,895,360	639,374,426	609,338,507	548,908,016	590,739,693	560,078,101

Narragansett Electric Company
Number of Customers by Rate Class

Rate Class	Jan-2006	Feb-2006	Mar-2006	Apr-2006	May-2006	Jun-2006	Jul-2006	Aug-2006	Sep-2006	Oct-2006	Nov-2006	Dec-2006
A-16	369,352	368,335	367,865	367,066	367,081	366,409	366,361	366,742	363,166	368,557	369,398	370,200
A-18	17,970	17,876	17,799	17,627	17,524	17,425	17,335	17,257	16,638	17,136	17,059	16,971
A-60	36,036	37,392	38,174	39,065	38,918	38,956	38,841	38,424	37,400	37,472	37,238	37,096
B-32	1	1	2	2	2	2	2	2	2	2	2	2
B-62	2	2	2	2	3	2	2	2	2	2	2	2
C-06	44,412	44,533	44,639	44,655	44,682	44,742	44,719	44,699	44,322	44,772	44,892	45,052
E-30	13	13	13	13	13	13	13	13	13	12	13	13
G-02	8,573	8,576	8,569	8,560	8,550	8,543	8,533	8,537	8,551	8,543	8,524	8,527
G-32	1,043	1,039	1,033	1,031	1,029	1,037	1,038	1,037	1,038	1,039	1,040	1,042
G-62	11	11	12	12	12	12	12	12	12	12	12	12
M-01	3	3	3	3	3	3	3	3	3	3	3	3
R-02	614	614	614	614	614	614	614	614	614	614	614	614
Streetlights	399	398	400	399	399	399	395	395	396	396	396	393
T-06	240	239	239	228	227	225	226	226	222	224	223	223
X-01	1	1	1	1	1	1	1	1	1	1	1	1
Total	478,670	479,033	479,365	479,278	479,058	478,383	478,095	477,964	472,380	478,785	479,417	480,151

Rate Class	Jan-2007	Feb-2007	Mar-2007	Apr-2007	May-2007	Jun-2007	Jul-2007	Aug-2007	Sep-2007	Oct-2007	Nov-2007	Dec-2007
A-16	370,722	371,190	372,299	372,765	372,137	371,762	371,360	370,540	370,318	370,237	376,005	377,891
A-18	16,886	16,827	16,759	16,691	16,612	16,520	16,428	16,367	16,291	16,204	16,328	16,304
A-60	37,032	37,211	36,918	36,531	36,849	36,633	36,502	37,028	36,970	36,684	30,814	29,920
B-32	2	2	2	2	2	2	2	3	3	3	3	3
B-62	2	2	2	2	2	2	2	2	2	2	2	2
C-06	45,207	45,087	45,381	45,482	45,522	45,580	45,572	45,615	45,666	45,676	45,869	45,954
E-30	13	13	13	13	13	13	13	13	13	13	13	13
G-02	8,544	8,402	8,541	8,530	8,530	8,530	8,535	8,525	8,529	8,535	8,547	8,554
G-32	1,045	1,037	1,048	1,052	1,053	1,052	1,054	1,050	1,049	1,053	1,052	1,055
G-62	12	12	12	12	12	12	12	11	13	13	13	14
M-01	3	3	3	3	3	3	3	3	3	3	3	3
R-02	614	614	614	614	614	614	614	614	614	614	614	614
Streetlights	393	394	394	394	394	395	395	396	396	396	396	395
T-06	222	221	219	216	216	216	216	216	216	216	216	216
X-01	1	1	1	1	1	1	1	1	1	1	1	1
Total	480,698	481,016	482,206	482,308	481,960	481,335	480,709	480,384	480,084	479,650	479,876	480,939

Rate Class	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
A-16	373,335	397,730	397,335	384,991	396,997	398,512	397,445	396,541	396,775	400,381	399,404	386,590
A-18	10,292											
A-60	29,706	31,054	31,100	30,655	31,604	31,692	31,616	31,444	31,352	27,020	30,106	28,982
B-32	3	3	2	3	3	2	3	2	2	2	2	3
B-62	44	2	2	2	2	2	2	2	2	2	2	2
C-06	44,775	46,050	45,996	44,827	46,119	46,262	46,290	46,292	46,107	46,139	46,449	45,421
E-30	13	13	13	13	13	12	12	12	12	12	12	11
E-40	5	10	9	8	9	9	9	8	8	9	9	4
G-02	8,343	8,464	8,509	8,463	8,492	8,410	8,508	8,438	8,321	8,395	8,482	7,988
G-32	1,025	1,009	1,034	1,042	1,047	1,027	994	1,040	1,015	1,047	1,033	850
G-62	13	13	12	11	12	13	10	13	14	14	10	10
M-01	3	3	2	3	3	3	3	3	3	3	3	3
R-02	223	614	614	614	614	614	614	614	614	614	614	614
S-10	2,862	2,863	2,851	2,859	2,880	2,848	2,842	2,847	2,843	2,864	2,829	2,826
S-14	394	393	393	394	395	395	396	397	397	397	397	396
T-06	223	217	215	214	216	213	215	216	216	214	216	214
X-01	1	1	1	1	1	1	1	1	1	1	1	1
Total	471,260	488,439	488,088	474,100	488,407	490,015	488,960	487,870	487,682	487,114	489,569	473,915

Rate Class	Jan-2009	Feb-2009	Mar-2009	Apr-2009	May-2009	Jun-2009
A-16	398,678	397,768	395,468	392,748	392,996	385,594
A-60	29,956	31,855	34,837	37,029	37,764	36,699
B-32	3	3	3	4	5	4
B-62	2	1	2	2	2	2
C-06	46,299	46,839	47,197	47,149	47,083	46,629
E-30	12	-	-	-	-	-
E-40	9	9	9	9	8	8
G-02	8,095	8,428	8,476	8,333	8,412	8,336
G-32	1,057	1,076	1,046	1,057	1,065	1,022
G-62	13	14	9	14	10	11
M-01	3	3	34	3	3	-
R-02	614	398	-	-	-	3
S-10	2,822	2,816	2,794	2,804	2,802	2,793
S-14	394	394	378	394	394	395
T-06	216	13	1	-	-	-
X-01	1	1	1	1	1	1
Total	488,174	489,618	490,255	489,547	490,545	481,497

Division Data Request 10-7

Request:

Referring to Dowd testimony, pages 4-5, as of what date was each change in benefits implemented?

Response:

The changes referenced on pages 4-5 went into effect on January 1, 2009.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 10-9

Request:

Referring to Dowd testimony, page 8, please provide documentation and calculations supporting the statement that 40% to 50% of the incentive pay is linked to individual objectives.

Response:

Please refer to Schedule NG-WFD-1 through Schedule NG-WFD-5 for documentation and calculations related to incentive pay.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 10-12

Request:

Referring to Exhibit NG-RLO-2, Page 20, please describe the duties and responsibilities of the seasonal employees hired from June to November.

Response:

The duties and responsibilities of the seasonal employees are as follows:

- Read meter; e.g. skips, misreads and books.
- Perform Field Credit Collection stops for payments.
- Turn Electric Service on and off at the meter location.
- Reconcile payment receipts received daily.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Division Data Request 10-14

Request:

Referring to the response to Workpaper NG-RLO-28, Page 4 and Division Data Request 1-1, please provide workpapers and calculations showing how salvage was taken into account in the determination of net removal costs.

Response:

The removal costs shown in the responses to Workpaper NG-RLO-28, Page 4 and DIV 1-1 reflect cost of removal net of salvage.

Prepared by or under the supervision of: Kimbugwe A. Kateregga

Division Data Request 10-15

Request:

Referring to the response to Division Data Request 1-2, please provide documentation to support the statement in Footnote 1.

Response:

Please see Schedule NG-JP-3 sponsored as an attachment of Company Witness John Pettigrew's pre-filed testimony for a breakdown of capital expenditures by month for calendar year 2009. The total net capital expenditures of $59,960,163 per that schedule served as the basis of the capital additions included in the Company's cost of service, as shown on Workpaper NG-RLO-28, Pages 2 and 3.

Per Schedule NG-JP-3, the net capital spending amounts for January, February and March 2009 are $3,438,425, $3,737,554 and $4,189,185, respectively. As shown in the table below, these amounts differ only slightly from the amounts provided in the response to Division Data Request 1-2 as a result of minor reclassifications made between budget classes which were reflected after the Company's filing in this proceeding.

	Jan-2009	Feb-2009	Mar-2009
Schedule NG-JP-3:			
Total Capital Spending	3,607,605	4,117,253	4,523,940
Less Public Requirements	(169,181)	(379,699)	(334,755)
Net Capital Spending	3,438,425	3,737,554	4,189,185
Data Request Division 1-2:			
Total Capital Spending	3,607,605	4,117,253	4,523,940
Less Public Requirements	(171,078)	(379,699)	(341,078)
Net Capital Spending	3,436,527	3,737,554	4,182,863
Difference:			
Total Capital Spending	-	-	-
Less Public Requirements	1,897	-	6,322
Net Capital Spending	1,897	-	6,322

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-16

Request:

Do the plant additions shown in the response to Division Data Request 1-2 include additions to transmission plant? If the response is affirmative, please show the additions to transmission plant and the additions to distribution plant separately.

Response:

The plant additions shown in the response to DIV 1-2 reflect additions associated with the Company's distribution operations and do not include additions to transmission plant.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-20

Request:

Referring to the response to Division Data Request 1-11, please explain the decrease in management employees from March 2009 to May 2009.

Response:

A group of professional engineers unionized in late 2007. As a result of that unionization the employees within the group were re-categorized on May 1, 2009 as union employees, decreasing the management population.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 10-21

Request:

Referring to the response to Division Data Request 1-11, please explain the increase in union employees from April 2009 to May 2009.

Response:

A group of professional engineers unionized in late 2007. As a result of that unionization the employees within the group were re-categorized on May 1, 2009 as union employees, increasing that population.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 10-22

Request:

Referring to the response to Division Data Request 1-13, please explain the increase in National Grid Service Company employees from March 2009 to May 2009.

Response:

Effective April 1, 2009 there was a restructuring within the Electric Distribution Operations organization that resulted in the employer of some employees to change from The Narragansett Electric Company to National Grid Service Company.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 10-24

Request:

Referring to the response to Division Data Request 1-26, why does the net balance on the supporting schedule show an excess, whereas Workpaper NG-RLO-29, Page 3 shows an unfunded balance of non-property related deferred FIT?

Response:

The net balance on the supporting schedule to Division Data Request 1-26 showed a deferred tax excess in error, as a result of the signs being incorrectly inverted. Please see the Attachment DIV 10-24 for the corrected schedule, which agrees with the unfunded non property-related deferred FIT reserves per Workpaper NG-RLO-29, Page 2.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company
Detail of Non-Property Related Deferred Taxes
Revised Version of Division Data Request 1-26

Line	Description	Balance Per Books	Deferred @ 35%	Unfunded/ (Excess)
		(a)	(b)	(c)
1	Non-Qualified Pension	$ (1,506,919)	$ (325,949)	$ 1,180,970
2	Property Tax	1,059,636	6,504,570	5,444,934
3	Worker's Compensation	(797,500)	(367,311)	430,189
4	Deferred Compensation	45,154	(83,114)	(128,268)
5	Environmental Reserve	(5,175,837)	(5,129,697)	46,140
6	Pension	(13,311,102)	(2,765,202)	10,545,900
7	OPEB	(15,626,047)	(26,180,140)	(10,554,093)
8	FAS 112	(808,811)	(1,160,077)	(351,266)
9	Vacation Accrual	(1,110,379)	(734,729)	375,650
10	Sales Tax Reserve	(808,600)	(664,096)	144,504
11	Storm Reserve	(7,379,378)	(7,366,543)	12,835
12	Interest Reserve	7,100	3,636	(3,464)
13	Regulatory Liabilities	854,480	(584,431)	(1,438,911)
14	Bonus Accrual	161,700	(31,373)	(193,073)
15	Unbilled Revenue	2,168,799	2,932,598	763,799
16	Bad Debts	(3,004,554)	(3,542,987)	(538,433)
17	Uninsured Claims	(1,606,472)	(1,666,700)	(60,228)
18	Debt	3,039,675	2,440,075	(599,600)
19	Rabbi Trust Unrealized	126,709	126,709	0
20	Other	1,638	0	(1,638)
21				
22	Total	$ (43,670,708)	$ (38,594,761)	$ 5,075,947

Division Data Request 10-25

Request:

Referring to the response to Division Data Request 1-26, with regard to the deferred taxes related to property taxes, why is balance per books $5.4 million different from the deferred taxes @ 35%?

Response:

The property tax timing difference represents an acceleration of the tax deduction over the book deduction due to a change in the lien date of property taxes in Rhode Island. The initial acceleration occurred before the adoption of FAS 109, in 1993, and the current tax benefits were immediately flowed through to ratepayers. At the adoption of FAS 109, the Company was required to record deferred taxes on the cumulative book/tax timing difference for all items. In the case of property tax, a deferred tax liability was recorded, but full recovery of that deferred tax liability from ratepayers was not agreed. From 1993 on, each fiscal year's timing difference was normalized and the Company recorded current income tax, offset by a deferred tax, both of which would have been recovered from ratepayers. The $5.4 million difference on the property tax line item represents pre-1993 deferred taxes required to be book kept under FAS 109 that have not yet been recovered from ratepayers.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-26

Request:

Referring to the response to Commission Data Request 1-48(1), Pages 1 and 2, were VERO (NECO) and VERO (NGSVCO) removed from pro forma operation and maintenance expenses? If the response is affirmative, please indicate where the VERO expenses were removed.

Response:

Yes, the VERO (NECO) and VERO (NGSVCO) amounts reflected in Commission Data Request 1-48(1), Pages 1 and 2, that were charged to operation and maintenance (O&M) expenses during the test year were removed from pro forma O&M expenses. These costs were removed as part of the elimination of merger-related costs to achieve shown on Schedule NG-RLO-2, Page 2, Line 14. Please note that the $1,837,515 in VERO (NGSVCO) pension costs in the response to Commission Data Request 1-48(1), Page 1, includes $63,484 in test year pension costs charged below the line rather than to O&M expenses.

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Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-28

Request:

Referring to the response to Commission Data Request 1-99, what was the disposition of the final balance remaining at the end of January 2006?

Response:

As shown in the attachment to Commission Data Request 1-99, which is a copy of Exhibit JAL-11, R.I.P.U.C. Docket No. 3788, the remaining balance of the Customer Credit that was credited to customers during 2005, after accounting for the Providence and East Providence customers' share of the credit, was a credit (under refund) of approximately $492,000. Because the amount was relatively small, the Company proposed, and the Commission approved, that the balance be used to offset a transmission service under recovery incurred during the period October 2005 through September 2006.

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 10-29

Request:

Referring to the response to Commission Data Request 1-104, why are none of the costs of the positions being allocated to gas operations?

Response:

As noted in the response to COMM 1-104, because essentially all of Rhode Island's gas customers are also electric customers of the Company, the Company is proposing to allocate 100 percent of the costs associated with the Consumer Advocates to electric operations and to recover those costs through electric distribution rates.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Navy Data Request 2-1

Request:

Please provide a copy of the following exhibits and schedules in the instant filing in native format (i.e., WORD and EXCEL or a compatible format). EXCEL workbooks should be provided with all formulas and links intact:

Company Witness Howard S. Gorman

Schedule NG-HSG-1
Schedule NG-HSG-2
Schedule NG-HSG-3
Schedule NG-HSG-4
Schedule NG-HSG-5
Schedule NG-HSG-6
Schedule NG-HSG-7
Schedule NG-HSG-8
Schedule NG-HSG-9
Schedule NG-HSG-10
Schedule NG-HSG-12

Company Witness Rudolph L. Wynter, Jr.
Schedule NG-RLW-1
Schedule NG-RLW-2
Schedule NG-RLW-3
Schedule NG-RLW-4

Company Witness Robert L. O'Brien
Schedule NG-RLO-3
Schedule NG-RLO-5
Schedule NG-RLO-6
Schedule NG-RLO-7

Response:

The Company is providing the requested spreadsheets in EXCEL format on CD-ROM.

Prepared by or under the supervision of: Howard S. Gorman, Rudolph L. Wynter, Jr. and Robert L. O'Brien

Navy Data Request 2-2

Request:

Please provide a copy of the following workpapers in the instant filing in native format (i.e., WORD and EXCEL or a compatible format). EXCEL workbooks should be provided with all formulas and links intact:

Company Witness Howard S. Gorman

Workpaper NG-HSG-2

Workpaper NG-HSG-3

Company Witness Robert L. O'Brien

Workpaper NG-RLO-9

Workpaper NG-RLO-10

Workpaper NG-RLO-22

Workpaper NG-RLO-24

Workpaper NG-RLO-25

Workpaper NG-RLO-26A

Workpaper NG-RLO-26B

Workpaper NG-RLO-26C

Workpaper NG-RLO-26D

Workpaper NG-RLO-26E

Workpaper NG-RLO-26F

Response:

The Company is providing the information in EXCEL format on CD-ROM.

Prepared by or under the supervision of: Howard S. Gorman and Robert L. O'Brien